Application for Case-by-Case MACT Determination

Bluewater Texas Terminal LLC
Bluewater SPM Project
Gulf of Mexico

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(revised April 2020)

DiSorbo
Environmental Consulting Firm

8501 North Mopac Expy | Suite 300 | Austin, TX 78759
512.693.4190 (P) | 512.279.3118 (F) | www.disorboconsult.com

Table of Contents

Section 1 Application Context........ 1-1
Section 2 Introduction........ 2-1
2.1 Applicant Information........ 2-1
2.2 Facility Background........ 2-1
2.3 Applicability of Clean Air Act § 112(g) to the Terminal........ 2-4
2.4 Process for Determining MACT........ 2-4
2.4.1 Regulatory requirements and guidance........ 2-4
2.4.2 Distinction between MACT determinations under 112(d) and 112(g)........ 2-5
2.5 Application Organization........ 2-10
2.6 Acronyms and Abbreviations........ 2-11
Section 3 Technical Background........ 3-1
3.1 Introduction........ 3-1
3.2 Classification of Crude Oil Tanker Vessels........ 3-1
3.3 Classification of Offshore Loading Facilities........ 3-2
3.3.1 Causeway- and Jetty-type Terminals........ 3-3
3.3.2 Platform-type Terminals........ 3-5
3.3.3 Multi-Buoy Mooring and Single Point Mooring (SPM)........ 3-5
3.3.4 Single Point Mooring........ 3-7
Section 4 Emissions Summary........ 4-1
4.1 Introduction........ 4-1
4.2 Methodology for Estimating Loading Emissions........ 4-1
4.2.1 Loading Loss Equation Input Parameters........ 4-2
4.2.2 Methane, H_2S, HAP, and speciated hydrocarbon constituents........ 4-4
4.3 Summary........ 4-6
Section 5 Applicability of CAA § 112(g)........ 5-1
5.1 Introduction........ 5-1
5.2 Offshore sources considered in establishing MACT Y........ 5-3
5.3 Discussion........ 5-14
5.3.1 Location on the OCS........ 5-14
5.3.2 Non-export OCS facilities........ 5-16
5.3.3 Crude Oil Export Facilities........ 5-18
Section 6 Similar Source Analysis........ 6-1
6.1 Introduction........ 6-1

Table of Contents (Continued)

6.2 Identifying “similar sources” 6-1

6.2.1 Sources considered in November 15, 2019, analysis 6-2

6.2.2 Sources considered in December 13, 2019, analysis 6-7

6.3 HAP Reductions achieved at similar sources 6-13

Section 7 Alternatives Analysis 7-1

7.1 Introduction 7-1

7.2 Control Alternatives Considered 7-2

7.2.1 Combined Work Practice 7-3

7.2.2 Vapor Recovery Unit 7-4

7.2.3 Vapor Combustor 7-8

7.2.4 Flare 7-20

7.2.5 Reverse lightering in lieu of constructing the project 7-22

7.2.6 Onshore vapor combustor 7-28

7.2.7 Controls onboard oil tanker 7-31

7.2.8 Recovery system onboard workboat 7-35

7.2.9 Controls onboard FSO constructed in lieu of SPM buoy 7-37

7.3 Proposed Emission Standards 7-40

7.4 Selected Control Technology 7-40

Section 8 Proposed MACT Requirements 8-1

Section 9 Maintenance Activities 9-1

9.1 Quantification of Emissions from Maintenance Activities 9-1

9.2 Maintenance Checklist and Pre-berthing checklist for BWTX Affiliate’s Tetney Facility 9-2

List of Tables

Table 2-1 Table of Acronyms 2-11

Table 3-1 Classification of Crude Oil Tankers 3-1

Table 3-2 Classification of Offshore Loading and Unloading Facilities 3-2

Table 3-3 Comparison of Proposed Marine Terminal Classifications 3-3

Table 4-1 True Vapor Pressures of Samples considered for Speciation Analysis— ASTM D6377 VPCR 4 4-3

Table 4-2 Estimated vapor phase weight fractions for HAP species 4-5

Table of Contents (Continued)

Table 4-3 NSR Pollutant Emission Rates 4-6

Table 5-1 Relevant MACT Y Terminology.......... 5-1

Table 5-2 Offshore Terminals with Subsea Lines Mentioned in MACT Y Docket 5-5

Table 6-1 Application of 112(g) “similar source” guidance to MACT Y sources.......... 6-3

Table 7-1 Summary of Alternatives Considered 7-1

Table 7-2 Platform-based vapor combustor as control alternative.......... 7-8

Table 7-3 HAP Cost Effectiveness Analysis for Innovative and Unproven Vapor Combustor on Platform 7-13

Table 7-4 Health, Safety, and Environmental Impacts for Offshore Platform.......... 7-17

Table 7-5 Scenarios Considereed 7-22

Table 7-6 Comparison of Emission Rates 7-23

Table 7-7 Summary of Impacts to the Aquatic Environment.......... 7-24

Table 7-8 Comparison of Casualty Risks.......... 7-24

Table 7-9 Summary of Time Requirements for Different Scenarios 7-25

List of Figures

Figure 2-1 Depiction of Facility Location (simplified) 2-2

Figure 2-2 Layout of PLEM, CALM Buoy, Under-Buoy Hose and Anchor Legs.......... 2-3

Figure 3-1 Causeway-type terminals (clockwise from top right): Tranmere (UK), Ras Tanura (KSA), Anacortes (WA), Point Richmond (CA).......... 3-4

Figure 3-2 Platform-type terminals (clockwise from top right): Freeport (Bahamas), Riverhead, NY, Drift River, AK, and Sitra (Bahrain).......... 3-7

Figure 3-3 Buoy-type offshore loading installations (clockwise from top right): Multi-buoy in El Segundo, (CA), SPM in Tetney (UK), SPM in Puerto José (Venezuela), and SPM in Barber’s Point (HI)3-9

Figure 4-1 Emission Calculations for VOC, Total HAP, H_2S, and GHG.......... 4-8

Figure 4-2 Emission Calculations for Hydrocarbon Species 4-9

Table of Contents (Continued)

Figure 7-1 Use of a flare on offshore floating production unit 7-21

Figure 7-2 Emission Calculations for Lightering Analysis 7-27

Figure 7-3 Conceptual Drawing for Vapor Recovery Pipeline with SPM loading 7-29

Figure 7-4 Trajectories for the Florida Voyager and the Mississippi Voyager 7-33

Figure 7-5 Trajectory for the *Randgrid* 7-34

Figure 7-6 Tandem Offloading from F(P)SO to Shuttle Tanker 7-39

Appendix A

SPM Design and Project Location Details

Applicable Pipeline Tariff

Deepwater Port License Application Excerpts

Correspondence from Classification Society

Correspondence with Control Device Vendor

Phillips 66 Tetney SPM Maintenance Checklist

Phillips 66 Tetney Pre-Berthing Checklist

Section 1
Application Context

Bluewater Texas Terminal LLC ("BWTX"), an affiliate of Phillips 66 Company, proposes to construct a deepwater port for export of crude oil in the United States Gulf of Mexico, approximately 15 nautical miles off the coast of San Jose Island, Texas.

The Deepwater Port Act ("DWPA", 33 USC § 1501 et seq.) requires that a person wishing to construct, own or operate a deepwater port obtain a license from the Secretary of Transportation. The proposed deepwater port will consist of two single point mooring (SPM) systems, subsea pipelines for transporting crude oil from shoreside storage points, and other equipment. The terminal meets the definition of a "deepwater port" (33 USC § 1502(9)) and is subject to the licensing requirements of the DWPA. BWTX must obtain a license from the U.S. Department of Transportation Maritime Administration (MARAD) before construction on the terminal may begin.

MARAD regulations implementing the DWPA require an analysis showing that the deepwater port will comply with all applicable Federal, Tribal, and State requirements for the protection of the environment (33 CFR § 148.105(z)), and also require that an applicant prepare and submit applications to the Environmental Protection Agency (EPA) for all permits required under the Clean Air Act (33 CFR § 148.700). EPA is a cooperating agency under the DWPA licensing program (33 CFR § 148.3(d)).

The following Clean Air Act requirements potentially apply to DWPA license applicants.

- Section 111 of the Clean Air Act requires EPA to promulgate performance standards ("NSPS") applying to each "new source" within specified source categories. EPA has not to date promulgated any NSPS applying to deepwater ports.
- Section 112 of the Clean Air Act requires EPA to promulgate National Emissions Standards for Hazardous Air Pollutants (NESHAP). Major sources of HAP must apply the Maximum Achievable Control Technology (MACT) for each applicable NESHAP. Additionally, each "new source" which is a major source of HAP must apply MACT, regardless of whether an applicable NESHAP has been promulgated.
- Clean Air Act New Source Review (NSR) requirements apply to the construction of a "major emitting facility" or a "major stationary source." Nonattainment NSR permitting applies to

construction in areas designated nonattainment for any pollutant for which a National Ambient Air Quality Standard (NAAQS) has been promulgated, while Prevention of Significant Deterioration (PSD) permitting applies to construction in areas designated attainment for at least one NAAQS pollutant. In the DWPA licensing context, additional preconstruction review that apply in the nearest coastal state ("minor NSR") may be imposed by EPA to the extent these are required under DWPA (33 USC § 1518(b)).

- Major sources (for purposes of either NESHAP or NSR) are subject to Clean Air Act Operating Permit ("Title V") requirements.

The proposed terminal will be a major source for purposes of the NESHAP, Title V and NSR programs. In order to meet the requirements of 33 CFR § 148.700, BWTX is submitting applications for all applicable Clean Air Act Permits, including:

1. An application for a case-by-case MACT determination ("NOMA");
2. A Title V permit application; and
3. A Prevention of Significant Deterioration (PSD) permit application.

This document represents a restatement of the Notice of MACT Approval (NOMA) application. The application was originally filed on May 31, 2019. Pursuant to several requests for information made by EPA Region 6, supplemental materials were filed on August 15, 2019, October 25, 2019, November 15, 2019, November 20, 2019, December 9, 2019, December 13, 2019, December 19, 2019, January 23, 2020, and March 18, 2020. This restated application is intended to abstract information previously submitted into a single, stand-alone document.

Section 2
Introduction

2.1 Applicant Information

<u>Applicant Name</u>:	Blue Water Texas Terminal LLC
<u>Applicant Mailing Address</u>:	2331 CityWest Blvd. Houston, Texas 77042
<u>Responsible Official</u>:	David Farris, Vice President
<u>Technical Contact</u>:	Chaitali Dave

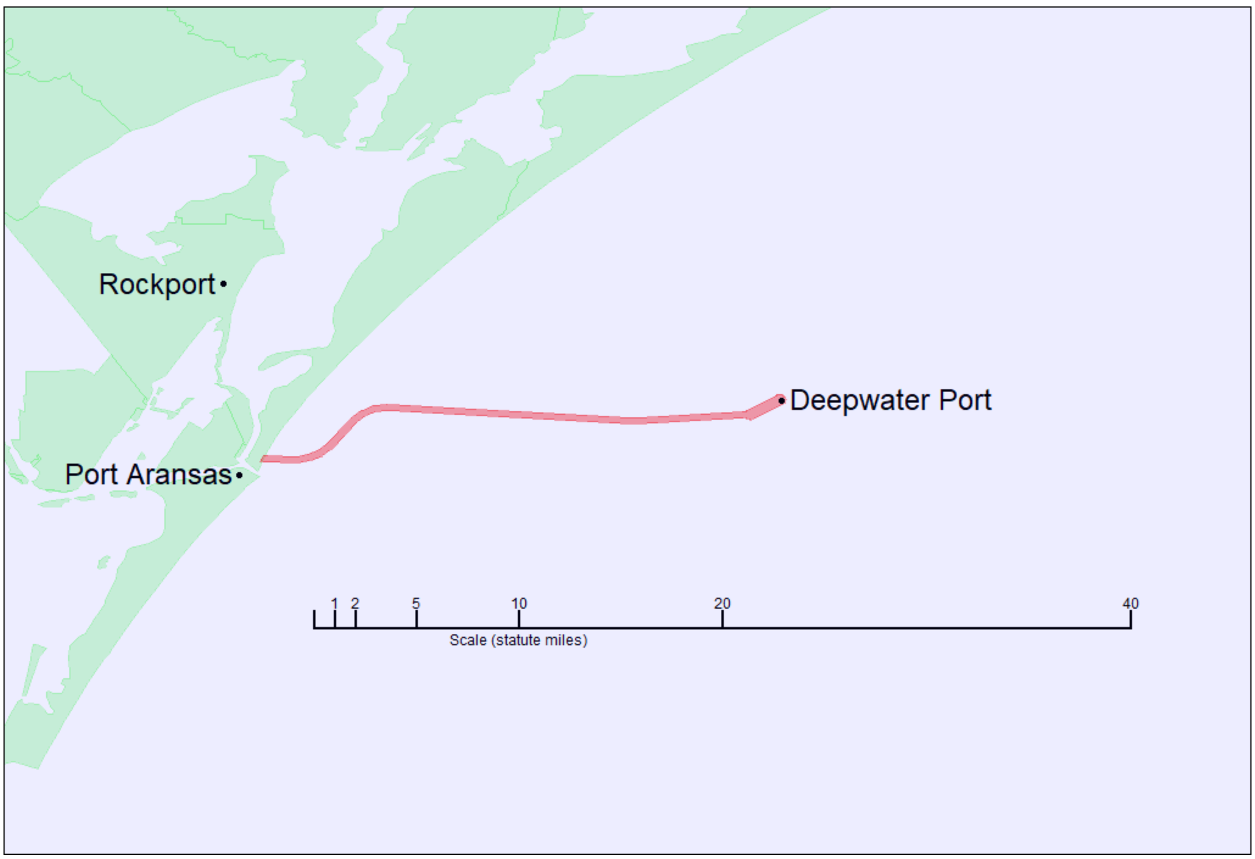
2.2 Facility Background

BWTX proposes to construct a deepwater port for export of crude oil via two Single Point Mooring (SPM) systems. The SPM's will be located at 27° 53′ 21.70″ N, 96°39′ 4.16″ W and at 27° 54′ 9.28″ N, 96° 37′ 41.23″ W, in BOEM lease block TX4, subdivisions 698 and 699 (see Appendix A). The facility will be approximately 15 nautical miles off the coast of San Jose Island. At the location of the deepwater port, the water depth is approximately 89 feet, which provides sufficient under keel clearance for a fully laden oil tanker in the Very Large Crude Carrier (VLCC) size range. A simplified depiction of the facility's location is presented in Figure 2-1. More detailed depictions are provided in Appendix A.

Land-based ports on the U.S. Gulf Coast do not provide sufficient draft for complete loading of VLCC's. In order to export crude oil, exporters must currently charter additional vessels to shuttle crude oil cargo between a shoreside terminal and a VLCC in an offshore lightering area. The proposed terminal will simplify the logistics associated with exporting crude oil on VLCC-size tankers. By conducting loading operations offshore, the project will also relieve inherent constraints and congestions in inland ports and waterways.

Loading of vessels is accomplished through two single point mooring (SPM) systems, each consisting of a pipeline end manifold (PLEM), a catenary anchor leg mooring (CALM) buoy, and hose strings. During loading operations, crude oil is pumped from the onshore valve and pipeline infrastructure to the deepwater port through two 30" offshore pipelines. The pipelines run along the seabed and terminate at a PLEM which is also affixed to the seabed. Each CALM mooring buoy is anchored by several catenary chains extending radially outward and down to the seabed. The buoy moves up and down with the tide and waves, and floats above the PLEM. The CALM buoy is partially submerged and its upper part is able to freely rotate about its base. One or more under-buoy hoses connect to the submerged portion of the CALM buoy and transfer crude oil from the PLEM to the CALM buoy. A floating hose string connects the CALM buoy to a tanker vessel in order to deliver crude oil. The proposed deepwater port will consist of subsea pipelines, single point mooring connections, mooring lines, a hose string and other necessary equipment.

Figure 2-1
Depiction of Facility Location (simplified)

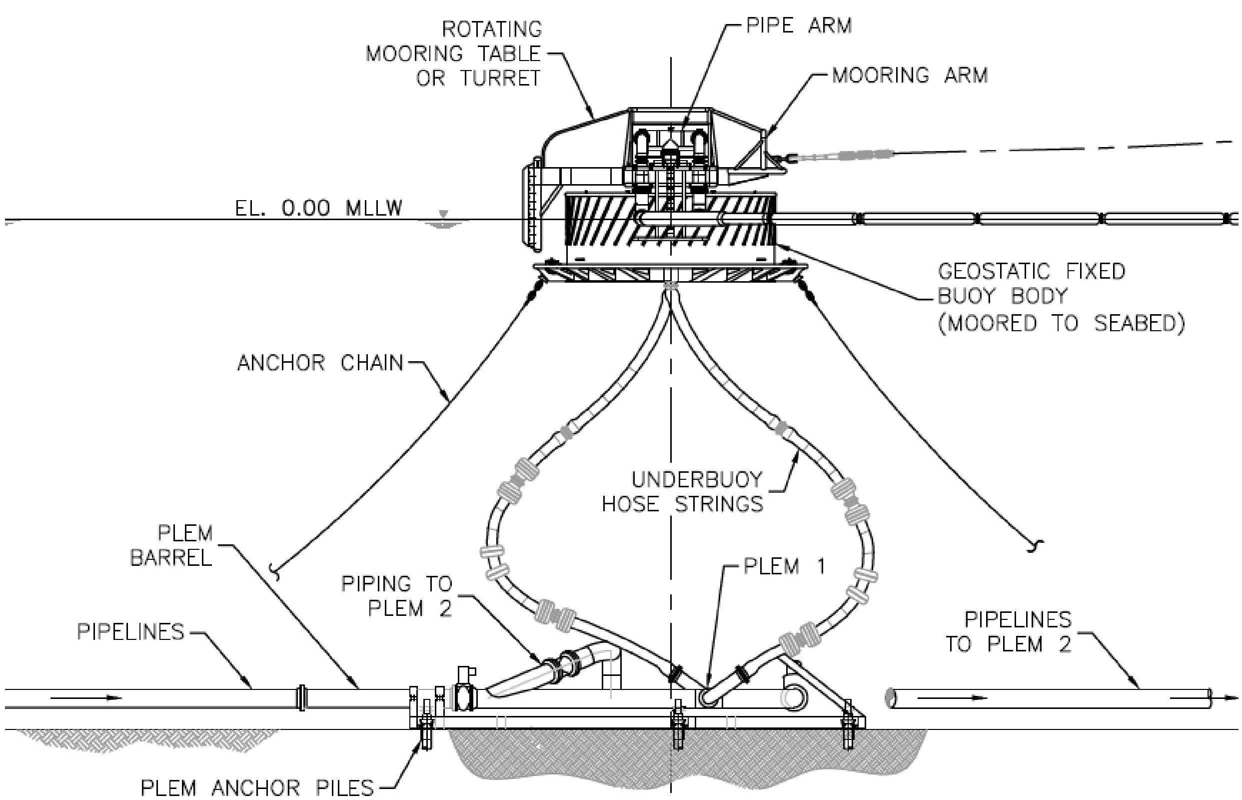


A shoreside pumping station ("booster station") will be used to transfer crude oil from an inshore storage terminal into the deepwater port. The shoreside and inshore facilities are not part of the deepwater port, and will instead be subject to Clean Air Act permitting requirements implemented by the Texas Commission on Environmental Quality (TCEQ). Air emissions associated with the booster station will be covered by several TCEQ Permits by Rule (30 TAC §§ 106.355, 106.472, 106.478, 106.511, 106.532, 106.263). Phillips 66 Pipeline LLC has also obtained a TCEQ standard permit (permit 158065) for a separate terminal known as the Midway Terminal. The permit covers eighteen floating roof tanks for intermediate storage of crude oil and appurtenances. The site is established under the TCEQ "Barnett Shale" Standard Permit for Oil and Gas Handling and Production Facilities (Eff. November 8, 2012). This terminal is intended to be multi-use in nature.

BWTX's original construction schedule was to begin construction on the deepwater port in March 2020, complete construction in November 2020, and start operations in July 2021. The actual construction will depend on the timeframe for securing all necessary permits and licenses, as well as economic factors.

Figure 2-2

Layout of PLEM, CALM Buoy, Under-Buoy Hose and Anchor Legs.



2.3 Applicability of Clean Air Act § 112(g) to the Terminal

The Clean Air Act requires all new major sources of HAP to meet MACT. If no applicable emission limitations have been established by EPA, then MACT must be determined case-by-case (CAA § 112(g)(2)(B)). No MACT standard has been promulgated for crude oil export facilities located on the United States Outer Continental Shelf (OCS), and such facilities are not included on the list of categories of major sources of HAP.[1] Since no MACT standard corresponds to BWTX's project, CAA § 112(g) preconstruction requirements apply.

EPA has promulgated NESHAP for the Marine Tank Vessel Loading Operations source category (40 CFR Part 63, Subpart Y, henceforth "MACT Y"),[2] and this is the source category which most closely corresponds to BWTX's proposed project. However, facilities similar to BWTX's proposed project did not exist at the time MACT Y was developed, and could not have existed due to technological and legal factors which have only become relevant during the past decade. A detailed analysis for non-applicability of MACT Y is provided in Section 5.

2.4 Process for Determining MACT

A person subject to section 112(g) preconstruction permitting requirements may, at the discretion of the permitting authority, apply for a Notice of MACT Approval (NOMA) under 40 CFR §§ 63.43(f)–(h) or instead apply for a MACT determination under certain other administrative procedures for preconstruction review established by a State or local jurisdiction.[3] BWTX is applying for a NOMA and has organized this application to meet the substantive requirements covered under 40 CFR §§ 63.43(d)–(e). Remarks below clarify BWTX's understanding of these requirements.

2.4.1 Regulatory requirements and guidance

Regulatory "Principles of MACT determinations" at 40 CFR § 63.43(d) require that MACT for a new major source be at least as stringent as the level of emissions control achieved in practice by the

[1] Cf. A-91-64 V-C-1 at 41. ("[T]*here may be source categories that have not yet been listed on the source category list for MACT standards ... In fact, EPA is required to list these categories as it becomes aware of them*.")

[2] 60 Fed. Reg. 48399. Sep. 19, 1995.

[3] 40 CFR § 63.43(c)(2).

best controlled similar source, as recommended by the applicant and approved by the permitting authority. The applicant's recommended MACT requirements must be based upon "available information" and must achieve the maximum degree of reduction in emissions of HAP that can be identified from the available information, taking into consideration cost and any non-air quality health and environmental impacts and energy requirements. The review of available information must consider alternatives for meeting the emission limitation recommended by the applicant.[4]

Section 112(g)(1)(B) of the Clean Air Act required EPA to publish guidance addressing the implementation of the 112(g) program. The guidance was "intended to be binding,"[5] and EPA has represented the *Federal Register* preamble associated with the final 112(g) rule (henceforth the "112(g) preamble")[6] as "guidance."[7] Therefore, BWTX has resorted to the 112(g) preamble in interpreting key portions of 40 CFR §§ 63.43(d)–(e). Although the proposed version of the 112(g) rule[8] was accompanied by a publication entitled "*Guidelines for MACT Determinations under Section 112(g)—PROPOSAL*,"[9] EPA indicated at the promulgation stage that this guidance document was not being finalized and would not become effective (unless finalized at a later date).[10] Although a similar publication (*Guidelines for MACT Determinations under Section 112(j) Requirements*)[11] *was* finalized, the only guidance responsive to Clean Air Act § 112(g)(1)(B) appears to be the regulation itself and the associated *Federal Register* promulgation notice.

2.4.2 Distinction between MACT determinations under 112(d) and 112(g)

The process for source-specific MACT determinations under CAA § 112(g)(2) differs from the process used by EPA in setting category-wide emission standards under CAA § 112(d). This difference is due to practical limitations on implementation of the two programs: The 112(g) program was intended to be implemented primarily by State permitting authorities, which do not have the resources or legal

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[4] 40 CFR §§ 63.43(e)(2)(x), (xii)

[5] 60 Fed. Reg. 8334. Feb. 14, 1995.

[6] 61 Fed. Reg. 68383. Dec. 27, 1996.

[7] Id. at 68391 ("*The guidance in this preamble is designed to help the permitting authority determine* ..." etc.)

[8] 59 Fed. Reg. 15504. Apr. 1, 1994.

[9] EPA Publication 450/3-92/007(b). March 1994.

[10] A-91-64 IV-C-1 at 89.

[11] EPA Publication 453/R-02-001. February 2002.

authority to collect and evaluate information about a broad class of stationary sources, as EPA does when it develops § 112(d) standards. Since the source categories themselves were not specified in detail when EPA developed its list of source categories,[12] development of category-specific standards also involves the establishment of definitions that create sharp boundaries for a specific category. The basic resource and legal limitations on state and local permitting authorities preclude this exercise for a case-by-case MACT evaluation.

Two specific differences between 112(d) and 112(g) that are of present relevance concern the treatment of similar sources and the consideration of cost, non-air environmental impacts, and energy requirements.

Source Categories and "Similar Sources"

The 112(g) preamble interprets the term "similar source," which appears in CAA § 112(d)(3), for purposes of administering the § 112(g) program:

> *The EPA believes that because the Act specifically indicates that existing source MACT should be determined from within the source category and does not make this distinction for new source MACT, that Congress intends for transfer technologies to be considered when establishing the minimum criteria for new sources. EPA believes that the use of the word "similar" provides support for this interpretation.*[13]

The same phrase takes on a different interpretation when EPA sets category-wide MACT standards under Section 112(d). For example, the D.C. Court of Appeals has referred to CAA § 112(d)(3) as "*requiring EPA to set NESHAP standards based on emissions reductions achieved by similar sources within the same NESHAP category.*"[14] EPA had discovered that certain of the sources considered in setting the MACT floor for cement kilns would not actually belong to the regulated source category (they would instead be classified as Commercial and Industrial Solid Waste Incineration [CISWI]

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[12] Cf. discussion in 112(g) preamble at 68395. ("*When the notice of initial list of categories of sources...was published...the EPA listed broad categories of major and area sources rather than narrowly defined categories...During the standard-setting process, EPA may find it appropriate to further subcategorize to distinguish among classes, types and sizes of sources.*")

[13] 61 Fed. Reg. 68395. Dec. 27, 1996.

[14] *Portland Cement Ass'n. v. EPA*. 665 F.3d 177, 186 (D.C. Cir. 2011).

units), but did not recalculate the MACT floor, a decision that was held to be arbitrary and capricious.[15] In a related case, one version of the Boiler MACT rule was vacated in its entirety due to a deficiency that the Court found in EPA's CISWI definition: since revising the definition would change "*the populations of units subject to EPA's boilers and CISWI rules*,"[16] the MACT floor would necessarily have to be recalculated before the rule could take effect.

Thus, in the context of 112(d) standard setting, there is clear precedent supporting the conclusion that "similar source" must be interpreted as referring to a source in the same category or subcategory as the proposed source. In 112(g) determinations, as noted above, the opposite is true. The differing interpretations of the phrase "similar source" give rise to a more fundamental distinction between 112(d) standards and 112(g) determinations which concerns how cost and other factors are considered.

Cost, non-air quality environmental impacts, and energy requirements

As caselaw and prior rulemakings make clear, when EPA sets § 112(d) standards, cost is not considered during the MACT floor determination:

> *EPA implements [112(d)] requirements through a two-step process. The agency begins by setting the minimum stringency standards required by section 7412(d)(3) for new and existing sources…Once the Agency sets statutory floors, it then determines, considering cost and other factors listed in section 7412(d)(2), whether stricter standards are "achievable." 42 U.S.C. § 7412(d)(2). The Agency calls such stricter requirements "beyond the floor" standards.*[17]

In contrast, under the § 112(g) program EPA effectively eliminated a MACT floor process of the type used in setting § 112(d) standards. In the "similar source" analysis which replaced the proposed MACT floor analysis, EPA chose to include cost considerations, among other factors:

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[15] "*[I]n none of EPA's proposals, final rules, or brief in this Court has EPA attempted to defend the principle that, in the face of a final and promulgated CISWI definition, data from CISWI kilns could now be considered in setting NESHAP standards.*" Id.

[16] *NRDC v. EPA*. 489 F.3d 1250, 1261 (D.C. Cir. 2007).

[17] *National Lime Ass'n v. EPA*. 233 F.3d 625, 629 (D.C. Cir. 2000).

> *The EPA believes that the practical use and effectiveness of any transfer technology should be generally comparable across emission units. While the particular pollutants emitted need not be the same, the following factors may be considered: the volume and concentration of emissions, the type of emissions, the similarity of emission points, and the cost and effectiveness of controls for one source category relative to the cost and effectiveness of those controls for the other source category, as well as other operating conditions.*[18]

Therefore, under the § 112(g) program, not only is cost considered in setting the minimum level of control, but it is considered in a different way than under § 112(d) standard setting. In setting 112(d) standards, EPA considers cost by determining the cost-effectiveness of particular controls under consideration during the beyond the floor analysis, an approach that has been upheld in litigation.[19] But EPA's guidance for assessing cost in making a "similar source" determination instead involves consideration of the *relative* cost of controls for two types of stationary source. EPA has taken the position that the Clean Air Act does not require it to use a particular form of cost analysis,[20] and it therefore seems reasonable to conclude that the "relative cost" methodology contemplated by the § 112(g) preamble fulfills the same function that cost-effectiveness calculations do in § 112(d) standard setting.

Terminological Differences between 112(d) and 112(g)

As noted above, standard setting under CAA § 112(d) involves a familiar two-step process. First, the "MACT floor" is established based on a comprehensive review of sources within the same category or subcategory; and second, "beyond the floor" requirements are evaluated based on cost and other factors. The two steps of the analysis are on equal footing and consider different types of information. For case-by-case MACT determinations under CAA § 112(g), on the other hand, the "similar source" analysis sets the minimum emission limitation, while the "alternatives" analysis considers different options for meeting such emission limitation. There is no exact parallel to the § 112(d) "MACT floor" or "beyond the floor" steps.

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[18] 112(g) preamble at 68395.

[19] E.g., *NRDC v. EPA*. 749 F.3d 1055, 1060–1061 (D.C. Cir. 2004).

[20] Id. at 1060.

Section 112(g)(2)(B) of the Clean Air Act requires that new and reconstructed major sources of HAP meet the "*maximum achievable control technology emission limitation…for new sources.*" In the 112(g) preamble, EPA interpreted this phrasing to refer to the "MACT floor" provision of the Clean Air Act for new sources, rather than to subsection 112(d) as a whole:

> *…the owner or operator must demonstrate to the permitting authority that emissions will be controlled to a level consistent with the "**new source MACT" definition in section 112(d)(3) of the Act.***[21]
>
> *…*
>
> *As required by section 112(g)(2)(B), this rule requires a case-by-case determination by the permitting authority that the technology selected by the owner or operator is consistent with what would have been required under section 112(d) of the Act. For constructed and reconstructed major sources, the minimum requirement for a case-by-case MACT determination, consistent with section 112(d), is the level of control that is achieved in practice by the best controlled similar source.*[22]

Consistent with this interpretation,[23] the 112(g) preamble contains an extended discussion on procedures for determining whether a particular source should be treated as a "similar source," but no discussion or guidance on making a "beyond the floor" determination. The "similar source" determination therefore fulfills the CAA § 112(g)(2)(B) directive that a case-by-case determination for the source be consistent with the § 112(d)(3) provisions applicable to new sources. The elements of § 112(d)(2) of the Act that are applicable to new sources are addressed by the rule's requirements that the source owner submit an analysis of cost, non-air quality environmental and health impacts, and energy requirements "*for the selected control technology*,"[24] where the selected control technology has been recommended following review of alternatives discernable from available

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[21] 112(g) preamble at 68385.

[22] Id. at 68394 (emphasis added).

[23] As a threshold manner, it should be noted that differing implementations of a MACT determination process under two separate statutory programs would be expected, following *Environmental Defense v. Duke Energy Corp*. 549 U.S. 561, 573 (2007) ("A given term in the same statute may take on distinct characters from association with distinct statutory objects calling for different implementation strategies.")

[24] 40 CFR § 63.43(e)(2)(xii).

information. BWTX has conducted a detailed survey of alternative control technologies for meeting the minimum emission limitation (Section 7), which contains cost information in some cases. However, only the cost evaluation for the selected control technology (combined work practice) has been included as responsive to the requirements of 40 CFR § 63.43(e)(2)(xii).

Because the "MACT floor" / "beyond the floor" framework does not apply to the evaluation of NOMA applications, these terms are not used in the analysis in Sections 6–7, which contain the "similar source" and "alternatives" analyses required under 40 CFR §§ 63.43(e)(2)(x)–(xii).

2.5 Application Organization

This application contains the information specified in 40 CFR § 63.43(e)(2), and is organized as follows:

- Section 2 is the present introductory section (§§ 63.43(e)(2)(i)–(v)).
- Section 3 provides background information that informs the discussion in various parts of the application (§ 63.43(e)(2)(xii)).
- Section 4 provides the facility's potential to emit for HAP and other regulated air pollutants (§§ 63.43(e)(2)(vi)–(ix)).
- Section 5 includes a detailed analysis of the applicability of case-by-case MACT for the facility, including an analysis of non-applicability for MACT Y (§§ 63.43(e)(2)(ii),(vii)).
- Section 6 is the "similar source" analysis for the facility (§ 63.43(e)(2)(xi)) which establishes the minimum emission limitation.
- Section 7 includes the "alternatives" analysis, which identifies alternative control technologies considered to meet the emission limitation and discusses cost, non-air quality environmental impacts and energy requirements for the selected control technology (§ 63.43(e)(2)(xii)). Additional information and evaluation requested by EPA Region 6 has been included in this section.
- Section 8 is the proposed case-by-case MACT standard for the facility (§§ 63.43(e)(2)(x)–(xi)).
- Section 9 contains information on maintenance activities which has been previously supplied to EPA.
- Appendix A contains detailed maps for the facility and other supplemental information and exhibits (§ 63.43(e)(2)(xii)).

2.6 Acronyms and Abbreviations

Acronyms and customary abbreviations in this application are as follows.

Table 2-1 Table of Acronyms

Term	Gloss
AIS	Automatic Identification System
APCD	Air Pollution Control District
BAAQMD	Bay Area Air Quality Management District
Bbl	Barrel (42 U.S. gallons)
BOEM	Bureau of Ocean Energy Management, U.S. Department of the Interior
BWTX	Bluewater Texas Terminal LLC
CAA	Clean Air Act (42 USC § 7401 et seq.)
CALM	Catenary anchor-leg mooring
DWPA	Deepwater Port Act (33 USC § 1501 et seq.)
dwt	Deadweight tonnage
EMT	Ellwood Marine Terminal
EPA	Environmental Protection Agency
FPSO	Floating Production, Storage and Offloading Unit
FSO	Floating Storage and Offloading Unit
GIMT	Gaviota Interim Marine Terminal
GIS	Geographic Information System
GOLA	Galveston Offshore Lightering Area
HAP	Hazardous Air Pollutants
Jones Act	Merchant Marine Act of 1920, as amended (46 USC § 55101 et seq.)
LOOP	Louisiana Offshore Oil Port
LNG	Liquefied Natural Gas
MACT	Maximum Achievable Control Technology
MARAD	Maritime Administration, U.S. Department of Transportation
MBbl	1,000 Bbl
NESHAP	National Emission Standards for Hazardous Air Pollutants
NPRM	Notice of Proposed Rulemaking
OCIMF	Oil Companies International Marine Forum
OCSLA	Outer Continental Shelf Lands Act
OS&T	Santa Ynez Unit Offshore Storage and Treatment Unit
PLEM	Pipeline end manifold
SALM	Single anchor-leg mooring
SCAQMD	South Coast Air Quality Management District
SLA	Submerged Lands Act (43 USC § 1301 et seq.)
SPM	Single-point mooring
TCEQ	Texas Commission on Environmental Quality
USCG	U.S. Coast Guard
VLCC	Very Large Crude Carrier
VOC	Volatile Organic Compounds

Section 3
Technical Background

3.1 Introduction

This section collects general background information that may be referred to in other parts of the application, including the § 112(g) applicability analysis, the similar source analysis, and the alternatives analysis (Sections 5, 6, and 7, respectively). Sections 3.2 and 3.3 discuss useful categorizations of crude oil tankers and offshore loading facilities, respectively.

3.2 Classification of Crude Oil Tanker Vessels

Crude oil can be exported through tankers falling into different size ranges. In this application, the following terms may be used to refer to a crude oil tanker based on its size in deadweight tons (dwt) and its approximate cargo tank capacity.

Table 3-1 Classification of Crude Oil Tankers

Tanker Type	Size Range (dwt)	Typical Cargo Tank Capacity (Bbl)
Handymax	30,000–55,000	300,000
Panamax	60,000–75,000	380,000
Aframax	80,000–120,000	500,000
Suezmax	125,000–170,000	1,000,000
VLCC	250,000–320,000	2,000,000

Fundamental tanker economies of scale are such that the use of larger tankers is both more efficient and more cost-effective for long haul trade. For long-haul voyages between the North America and the Asia-Pacific region, use of a VLCC rather than an Aframax can create a savings on freight costs equivalent to approximately $1/Bbl of cargo.[25]

[25] Typical charter rates accessed February 14, 2019, at https://www.hellenicshippingnews.com/category/report-analysis/weekly-tanker-time-charter-estimates/.

A tanker's draft, which is the depth its keel extends below the water's surface, is dependent upon the vessel's design scantlings, water salinity, and the weight it carries (cargo, ballast, fuel, water, stores). Currently, crude oil export terminals in the United States Gulf Coast are capable of accommodating fully laden Panamax and Aframax tankers. Some terminals are able to accommodate a fully-laden Suezmax. While two terminals in Texas have recently practiced the partial loading of a VLCC, with an additional terminal expected to be online by early 2020, no shore-based terminal has sufficient draft to accommodate a fully laden VLCC. Complete loading of a VLCC in the Gulf of Mexico can be accomplished at the Louisiana Offshore Oil Port (LOOP), or via reverse lightering.

3.3 Classification of Offshore Loading Facilities

Facilities used to transfer cargo between a tanker vessel and an on-shore storage facility can be distinguished by their means of construction, operation, and their location with respect to the shore. Five main types of loading facilities are discussed, and these are summarized in Table 3-2.

Table 3-2 Classification of Offshore Loading and Unloading Facilities

Characteristic	Terminal Type				
	Causeway	Jetty	Platform	Multi-buoy	SPM
Distance from Shore	0–5 mi.	0–5 mi.	0–5 mi.	≈ 1 mi.	1–20 mi.
Mooring	Fixed	Fixed	Fixed	Fixed	Ship rotates freely
Attachment to Sea Floor	Pilings	Pilings	Pilings	Anchors	Anchors
Location of Piping	Above water	Above Water	Subsea	Subsea	Subsea
Access	Motor vehicle, service vessel	Helicopter, service vessel	Helicopter, service vessel	Service vessel	Service vessel
Loading Equipment	Loading Arms	Loading Arms	Loading Arms	Submersible Hose	Floating Hose

Classification of offshore loading facilities informs BWTX's proposed finding of applicability of § 112(g) requirements, the similar source analysis, and the alternatives analysis. In order to develop the classification, BWTX identified approximately 70 offshore loading and unloading facilities around the world, with an emphasis on locating all offshore facilities in the United States. Facilities were identified through a two-step process. First, the registry numbers of various crude oil and chemical tankers were obtained, and AIS data transmissions for these vessels were purchased from a commercial vessel tracking service. Next, the vessels' itineraries over a particular time period (typically 3–6 weeks) were plotted with GIS software, and the ports where they called were identified through satellite photography. The following classification is based on review of the satellite photography as well as consultation of published material describing individual terminals or terminal construction practices.[26]

The typology arrived at by the preceding method is consistent in its main details with systems of classification presented in other publications, which emphasizes the broad relevance of the functional distinctions proposed. The remainder of this section briefly discusses each of the five types of offshore loading facilities, providing satellite photographs where available.

Table 3-3 Comparison of Proposed Marine Terminal Classifications

Source	Category Name				
CCC 1988[27]		Fixed berth	Sea island	Multiple Buoy	Single Buoy
Marcus et al 1975[28]	Conventional pier		Sea island pier	Multiple buoy berth	SPM systems
Present work	Causeway	Jetty	Platform	Multi-buoy	SPM

3.3.1 Causeway- and Jetty-type Terminals

Causeway-type terminals are those which are connected to shore by a long causeway containing pipe racks and a road for motor vehicle access to the dock. Piping and utilities run along the causeway, and the berth itself consists of a dock containing loading arms and other equipment. In some cases, parking facilities, buildings, and other equipment may be located at different points along the causeway. The majority of offshore loading terminals identified in the United States are of the causeway type, and these have distances to shore ranging from 0.3–0.9 statute miles. Such

[26] Cf., for example, U.S. Department of the Interior Minerals Management Service. 1990. *Pacific Update: August 1987–November 1989*. OCS Information Program publication MMS 90-0013, for a listing of all marine terminals existing in California as of 1989.

[27] California Coastal Commission. December 1988. *Oil and Gas Activities Affecting California's Coastal Zone: A Summary Report*. Cf. Sec. VI.

[28] Marcus, Henry S. et al.. "Deepwater Ports in the United States: Technology in Perspective." in National Academy of Sciences. 1975. Background Papers on Seafloor Engineering. Volume I: National Needs in Seafloor Engineering. 107–130.

terminals are found at sites in Washington, California, New York, St. Croix, and Puerto Rico. Several causeway-type terminals have been observed in the Persian Gulf with above-water pipe racks extending up to five statute miles from shore.

Figure 3-1 Causeway-type terminals (clockwise from top right): Tranmere (UK), Ras Tanura (KSA), Anacortes (WA), Point Richmond (CA)

Jetty-type terminals are similar to causeway-type terminals in that they have above-water pipe racks and a loading berth consisting of a fixed platform with loading arms. However, the jetty does not provide for road access to the loading berths. These installations therefore have more limited space for installation of equipment in areas other than on the loading platform. Jetty-type terminals at international locations have been identified with berths up to 1.0 miles from shore.

3.3.2 Platform-type Terminals

Platform-type offshore terminals resemble causeway- and jetty-type terminals in that they are permanently fixed to the sea floor by pilings. The main difference is that they are not connected to the shore by a causeway or above-water pipe rack. Instead, piping runs along the seabed to shore, and access to the dock by personnel is via service vessel or helicopter. Like causeway- and jetty-type terminals, they tend to be sited in sheltered locations somewhat close to shore.

Six terminals of this type have been identified, two of which are located in the United States.[29] In the photographs, loading arms and mooring lines can be seen, as well as a helicopter landing pad in two cases. In one photograph, the piping run along the seabed is visible as a dark line exiting the upper-right corner of the photograph. The installation the greatest distance from shore (Venezuela) is approximately 3.6 statute miles from shore at its most distant point.

3.3.3 Multi-Buoy Mooring and Single Point Mooring (SPM)

Buoy-type facilities (multi-buoy and SPM) differ from jetty-type terminals in that they have no platform or loading arms. Tankers are moored in open-water locations by means of one or more buoys, and loading takes place through a hose connected to a pipeline end manifold (PLEM) attached to the sea floor.

Multi-Buoy Mooring

In a conventional, multi-buoy mooring (also known as "spread mooring"), a vessel is held in a relatively fixed position by means of two or more mooring buoys, as well as by its own anchors. Multi-buoy moorings are only suitable for relatively sheltered areas or where the directions of wind, wave and current are aligned along one prevalent direction.[30] Multi-buoy moorings are generally not used for loading tankers greater than 100,000 dwt.[31] Numerous multi-buoy mooring facilities have been identified in the United States, almost all of which are located in California coastal waters (generally

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[29] Additionally, a platform-type terminal operated in San Francisco Bay prior to 1995 is mentioned elsewhere in this application.

[30] Pederson, K.I. 1977. Offshore Oil Loading Facilities. ASCE Seminar on Marine Construction. Accessed 13-Feb-2019 at http://www.sofec.com/whitePapers/1977%20Offshore%20Oil%20Loading%20Facilities.pdf.

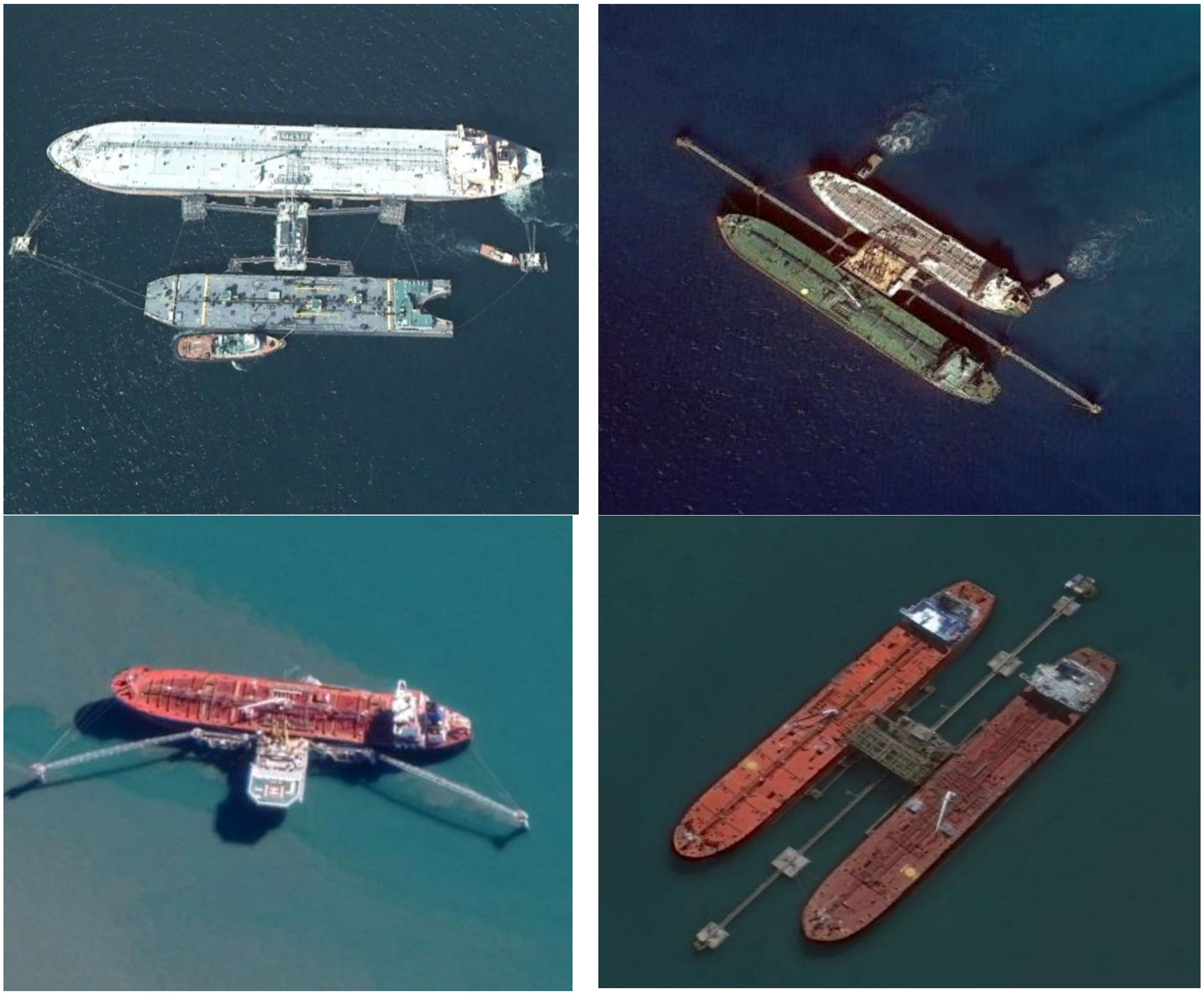
[31] Marcus, Henry. "Maritime Transportation Systems." In Kildow, Judith ed. September 1977. *International Transfer of Marine Technology: A Three-Volume Study*. Massachusetts Institute of Technology Sea Grant Program. Report No. MITSG 77-20. II:81–142. at 123.-

0.5–1.5 statute miles from shore), though many of these have been abandoned and/or dismantled during the past 25 years. Loading of crude oil onto tankers via spread mooring buoys is documented as early as 1920 at locations along the Atlantic coast of Mexico.[32]

Multi-buoy moorings are normally designed with a submersible hose which rests on the seabed when not in use. These facilities are identifiable from satellite photography by a characteristic semi-elliptical array of buoys.

[32] U.S. Navy Hydrographic Office. 1920. Central America and Mexico Pilot (East Coast). Washington: Government Printing Office. at 338, 344. Cf. also "Ocean-Bottom Filling Station." *Popular Mechanics*. October 1951. 136–138.

Figure 3-2 Platform-type terminals (clockwise from top right): Freeport (Bahamas), Riverhead, NY, Drift River, AK, and Sitra (Bahrain)



3.3.4 Single Point Mooring

In a single-point mooring (SPM) or “monobuoy,” the tanker is moored at a single point only, and is thus allowed to freely rotate around the mooring as wind and sea conditions change. While SPM’s may be located near shore, they can also be installed in locations further from shore where sea conditions are more variable. SPM installations use a floating hose string which rests on the water surface when not in use, and can be identified from satellite imagery by the presence of the floating hose string. The first CALM SPM was placed into operation in 1959 at the Port of Dolaro, Sweden.[33]

While SPM's are reported as having been installed considerable distances from shore, publicly available satellite imagery is of lower resolution far from the shore, so photographs of the most distant installations are not available at high resolution. Installations observed near shore are at least one mile from shore. The distance from shore can be extended to the amount necessary to achieve the required draft. The LOOP installation noted previously is approximately 20 statute miles from shore, while the proposed SPM system will be approximately 15 nautical miles from shore.

Figure 4-3 shows satellite photographs of four buoy-type facilities used to load liquids to/from shore, including one multi-buoy mooring and three SPM's.

[33] Lanquetin, B. 2005. "More than 30 Years' Experience with F(P)SO's and Offloading Techniques." Paper presented at the International Petroleum Technology Conference in Doha, Qatar, 21 – 23 November 2005.

Figure 3-3 Buoy-type offshore loading installations (clockwise from top right): Multi-buoy in El Segundo, (CA), SPM in Tetney (UK), SPM in Puerto José (Venezuela), and SPM in Barber's Point (HI)

Section 4
Emissions Summary

4.1 Introduction

This section describes the method for estimating potential emission rates of VOC, H_2S, GHG, HAP, and speciated hydrocarbon constituents.

VOC, H_2S, and GHG emission rates are calculated to determine PSD applicability. HAP emission rates are calculated to identify the pollutants requiring MACT and to evaluate emission control issues.[34] Speciated hydrocarbon constituent emission rates are calculated in support of a dispersion modeling analysis previously requested by EPA.

Emission calculations are presented at the end of this section as Figure 4-1 and Figure 4-2.

4.2 Methodology for Estimating Loading Emissions

Emissions are generated during loading operations when vapors in the headspace of a ship's cargo tank are displaced. The cargo tank headspace includes inert gas from the ship's onboard inert gas generator, crude oil vapors from any previous cargo, and crude oil vapors generated in the course of loading. Crude oil vapors may contain methane and VOC, while inert gas contains CO_2.

In order to calculate VOC emissions, a loading loss emission factor, is estimated following AP-42, Section 5.2, equation (1). Once a loading loss emission factor (L_L) is determined, an emission rate is determined by multiplying the loading loss emission factor by the crude oil throughput in the appropriate units. The loading loss factor is calculated as follows.

$$L_L = S\frac{PM}{RT}$$

The dimensionless saturation factor, S, accounts for the incomplete level of saturation of the cargo tank's headspace. S is assumed to be 0.2 for ship loading. P, M, and T represent the VOC vapor pressure, vapor phase molecular weight, and liquid surface temperature, respectively. The ideal gas

[34] Cf. 61 Fed. Reg. 68393 (Dec. 27, 1996).

constant, R, has a numerical value of 1/12.46 when expressed in units of (Mgal·psia)/(lb-mol·°R). For units of (MBbl·psia)/(lb-mol·°R), R has a value of 1/(42×12.46), or 1/523.32.

In order to calculate emissions of CO_2 from displacement of inert gas vapors, the loading loss equation is used with S=1, since CO_2 will only be present in the vapor phase. In other words, it is assumed that the volume of inert gas emitted is equal to the total volume of liquid loaded. The partial pressure of CO_2 is conservatively estimated based on the CO_2 content of the inert gas, approximately 14 vol.%.[35]

4.2.1 Loading Loss Equation Input Parameters

Vapor Phase Molecular Weight

The vapor phase molecular weight is estimated based on the results of a speciation analysis submitted on July 31, 2019. The vapor phase molecular weight is the harmonic mean of the molecular weights of the vapor phase constituents, weighted by their mass fractions. The worst-case (i.e., maximum) vapor phase molecular weight determined from the analysis is 59.37 lb/lbmol on an annual average and 60.32 lb/lbmol on a 1-hr average.

Vapor phase molecular weights calculated in this manner are more conservative (higher) than the default value of 50 lb/lbmol given in AP-42, Chapter 7, Table 7.1-2.

Liquid Temperature

T is taken as the monthly average annual ambient temperature for Corpus Christi, as reported in AP-42, Chapter 7, or 531.72°R (72.1°F).

True Vapor Pressure

The annual-average true vapor pressure of the liquid is based on a maximum Reid Vapor Pressure of 9.5. This value is a specification in the tariff for the crude oil pipeline which will transport crude oil to the SPM facility. Reid Vapor Pressure is converted to True Vapor Pressure using AP-42, Chapter 7, Equation 7.1-13b. At 72.1°F, RVP 9.5 corresponds to 8.44 psia. Therefore, P is taken to be

[35] This corresponds to a partial pressure of 2.1 psia. "Inert Gas Generator." SurviTech Group. Accessed April 24, 2019 at https://survitecgroup.com/media/339875/survitec-inert_gas_generator.pdf.

8.44 psia on an annual average. The worst-case, 1-hr average true vapor pressure of 11 psia is also based on the tariff specification. For purposes of estimating the VOC emission rate, the crude oil vapors are conservatively assumed to be 100% VOC. A copy of the current pipeline tariff on file with the Texas Railroad Commission (RRC) is included in Appendix A.

The use of a pipeline tariff as the basis for worst-case vapor pressure is conservative and is consistent with the range of samples considered in developing the July 31, 2019, speciation analysis. For the five samples considered in that analysis, true vapor pressures at 100° F were determined as follows following ASTM D6377 methodology.

Table 4-1 True Vapor Pressures of Samples considered for Speciation Analysis—ASTM D6377 VPCR 4

Sample Number	Provenance/ Specification	TVP @ 100° F (psia)
Sample 1	Eagle Ford	8.41
Sample 2	Powder River	5.48
Sample 3	WTI	7.84
Sample 4	Bakken	11.09
Sample 5	WTI-Light	8.06

Finally, the use of AP-42, Chapter 7, Equation 7.1-13b in estimating potential emission rates is conservative because that equation tends to overpredict true vapor pressures vis à vis empirical determination using ASTM D6377 methodology.[36]

Sample Calculation for L_L

The loading loss factors for VOC are therefore calculated as follows for 1-hr and annual averaging periods:

$$E_{VOC} = \frac{12.46 \times 42 \times 0.2 \times 11 \times 60.32}{554.67} = 125.2 \text{ lb/MBbl}$$

$$E_{VOC} = \frac{12.46 \times 42 \times 0.2 \times 8.44 \times 59.37}{531.72} = 98.6 \text{ lb/MBbl}$$

[36] Cf. AP-42 Chap. 7 (Nov. 2019 ed.) at 7.1-79 (Note 2).

The loading loss factor for CO_2 is calculated as follows:

$$E_{CO_2} = \frac{12.46 \times 42 \times 1 \times (14\% \cdot 14.7) \times 44.01}{531.72} = 89.1 \text{ lb/MBbl}$$

4.2.2 Methane, H_2S, HAP, and speciated hydrocarbon constituents

Emission rates of methane, hydrogen sulfide, HAP, and speciated hydrocarbon constituents are estimated by multiplying the VOC emission rate by the estimated vapor phase weight fraction of the constituent of interest.

A speciation analysis submitted on July 31, 2019, determined maximum vapor phase weight fractions for methane and speciated hydrocarbon constituents for five crude oil samples representative of the types of crude oil that BWTX intends to handle at the facility. Additionally, basic assay data (discussed in the same submission) were considered for fourteen samples to determine the worst-case flow-weighted annual average H_2S concentration of crude oil to be handled at the facility.

Methane

Of five samples evaluated in the July 31, 2019, analysis, only one contained any detectable amount of methane. The highest calculated vapor phase mass fraction of methane is less than 0.04 %. This is consistent with the expectation that most methane present in the crude oil will have weathered out by the time it reaches the storage terminal upstream of the SPM facility.

Hydrogen Sulfide

The applicable pipeline specification limits the H_2S content of crude oils to 10 ppmw H_2S in the liquid phase. On a flow-weighted annual average, the H_2S content of crude oils will not exceed 2 ppmw in the liquid phase. The vapor phase H_2S content of the crude oil vapors is estimated using published K-factor[37] correlations for H_2S.[38] Based on a reference temperature of 80°F, a K-factor of 23 is

[37] For a vapor liquid equilibrium system, the K-factor for component *i* is the ratio of the vapor phase mole fraction of the component to the component's liquid phase mole fraction. I.e., $K_i = y_i/x_i$.

[38] *Gas Processors Suppliers Association Engineering Data Book*. 1957 ed.

used. Calculated vapor phase mass fractions are 598 ppmw and 121 ppmw for 1-hr and annual averaging periods, respectively.

While the methodology used to estimate vapor phase H_2S concentrations from the liquid phase H_2S content of a crude oil is approximate in nature, its results correspond approximately to results reported using current analytical methods. Nicholson and O'Brien report partition coefficients of 80 – 300 vppm/lppm for a variety of crude oil samples,[39] which is consistent with the partition coefficient (106 vppm/lppm) implied by the proposed methodology.

Individual and Total HAP

Vapor phase weight fractions were calculated for each species of HAP in the five samples analyzed for the July 31, 2019, submission. All HAP species which were positively identified in any sample were considered. The worst-case temperature scenario (T=95° F) was conservatively used to estimate weight fractions for both 1-hr and annual averaging periods.

Table 4-2 Estimated vapor phase weight fractions for HAP species

Constituent	Sample 1	Sample 2	Sample 3	Sample 4	Sample 5	MAX
n-Hexane	3.20%	3.09%	3.57%	3.13%	3.57%	3.57%
Benzene	0.34%	0.06%	0.35%	0.20%	0.34%	0.35%
Toluene	0.19%	0.13%	0.29%	0.13%	0.33%	0.33%
m-Xylene	0.10%	0.05%	0.05%	0.04%	0.07%	0.10%
p-Xylene	0.05%	0.06%	0.03%	0.03%	0.04%	0.06%
o-Xylene	0.02%	0.02%	0.02%	0.01%	0.02%	0.02%
Ethylbenzene	0.01%	0.02%	0.03%	0.01%	0.02%	0.03%
Styrene	0.001%	—	—	—	—	0.001%
Total	3.91%	3.42%	4.34%	3.55%	4.40%	4.40%

[39] Nicholson, Mike and O'Brien, Tim. 2001. "Hydrogen Sulfide in Petroleum." Presentation made at the meeting of the Crude Oil Quality Association, Houston, TX. May 31, 2001. Accessed April 26, 2019 at http://www.coqa-inc.org/docs/default-source/meeting-presentations/20010531H2S.pdf.

Total HAP emission rates are based on the worst-case total HAP weight fraction of 4.4%, while individual HAP emission rates are based on the highest weight fraction calculated for any sample. Therefore, the sum of the individual HAP percentages is 4.45% rather than 4.40%.

Individual Hydrocarbon Species

Emission rates were calculated for individual species for the purposes of the dispersion modeling analysis requested by EPA. Emission rates were calculated for each species detected in any sample using the same approach as was used to estimate individual HAP emission rates. Two differences are noted, however. First, 1-hr and annual average weight fractions were calculated separately. Second, emission rates were determined for "surrogate groups" rather than for individual chemicals. A "surrogate group" is the group of all chemicals sharing an entry in the TCEQ Toxicity Factor Database. For example, the n-hexane surrogate group consists of n-hexane, 2-methylpentane, 2,2-dimethylbutane, and 3-methylpentane, since the latter three chemicals are designated as "surrogated to" n-hexane in the Toxicity Factor Database. Thus, the calculated n-hexane emission rate for purposes of dispersion modeling is based on vapor phase weight fractions of 8.29 wt.% (1-hr) and 7.25 wt.% (annual) rather than 3.57 wt.%, as was used in the individual HAP calculations. Individual surrogate group emission rates sum to greater than 100%.

4.3 Summary

Emission calculations for all constituents evaluated are summarized in Figure 4-1 and in Figure 4-2 (below).

Of the PSD pollutants, the VOC emission rate exceeds applicable SER of 40 tpy. The H_2S emission rate is less than the applicable SER of 10 tpy, while the GHG emission rates are less than the threshold above which GHG are subject to regulation. Therefore, substantive PSD requirements apply to VOC, but not to H_2S or GHG.

Potential emission rates of HAP exceed 10 tpy for n-Hexane, Benzene, Toluene, m-Xylene, p-Xylene, and Xylene (all isomers). Potential emission rates of combined HAP exceed 25 tpy.

Table 4-3 NSR Pollutant Emission Rates

Pollutant	Avg. Period	Emission Rate
VOC	1-hr	10016.28 lb/hr
VOC	Annual	18935.82 tpy

Pollutant	Avg. Period	Emission Rate
H_2S	1-hr	5.99 lb/hr
H_2S	Annual	2.30 tpy
GHG (mass basis)	Annual	17119.36 tpy
GHG (CO_2e basis)	Annual	17259.50 tpy

Figure 1 Emission Calculations for VOC, Total HAP, H_2S, and GHG

Annual Average Emiss. Factor

Quantity	Value	Units
Ideal Gas Constant	0.0019109	MBbl psia / lbmol R
Saturation Factor	0.2	Dimensionless
True Vapor Pressure	8.44	psia
Temperature	72.1	F
Vapor Phase MW	59.37	lb/lbmol
L_L	98.6	lb/MBbl

Hourly Average Emiss. Factor

Quantity	Value	Units
Ideal Gas Constant	0.00191088	MBbl psia / lbmol R
Saturation Factor	0.2	Dimensionless
True Vapor Pressure	11	psia
Temperature	95	F
Vapor Phase MW	60.32	lb/lbmol
L_L	125.2	lb/MBbl

Carbon Dioxide Emiss. Factor

Quantity	Value	Units
Ideal Gas Constant	0.001910877	MBbl psia / lbmol R
Saturation Factor	1	Dimensionless
True Vapor Pressure	2.058	psia
Temperature	72.1	F
Vapor Phase MW	44.0098	lb/lbmol
L_L	89.1	lb/MBbl

H_2S Weight Fraction, Annual

Quantity	Value	Units
Liquid phase mass fraction	2	ppmw
Liquid phase mol. Wt.	156.75	lb/lbmol
Vapor phase mol. Wt.	59.37	lb/lbmol
K-factor (80 F)	23	y / x
Vapor phase mass fraction	121	ppmw
Implied partition coefficient	106	vppmv/lppmw

H_2S Weight Fraction, Hourly

Quantity	Value	Units
Liquid phase mass fraction	10	ppmw
Liquid phase mol. Wt.	156.75	lb/lbmol
Vapor phase mol. Wt.	60.32	lb/lbmol
K-factor (80 F)	23	y / x
Vapor phase mass fraction	598	ppmw
Implied partition coefficient	106	vppmv/lppmw

Methane Weight Fraction

Quantity	Value	Units
Liq. Phase Mass Fraction	0.4964	ppmw
Liquid phase mol. Wt.	189.92	lb/lbmol
Vapor phase mol. Wt.	58.09	lb/lbmol
K-factor (95 F)	190	y / x
Vapor phase mass fraction	308	ppmw
Methane GWP	25	lb CO_2e/lb

NSR Pollutant Emission Rates

Pollutant	Avg. Period	Emission Rate
VOC	1-hr	10016.28 lb/hr
VOC	Annual	18935.82 tpy
H_2S	1-hr	5.99 lb/hr
H_2S	Annual	2.30 tpy
GHG (mass basis)	Annual	17119.36 tpy
GHG (CO_2e basis)	Annual	17259.50 tpy

HAP Species Emission Rates

Pollutant	ER_lb/hr	ER_tpy
Total HAP	440.72	833.18
n-Hexane	357.58	676.01
Benzene	35.06	66.28
Toluene	33.05	62.49
m-Xylene	9.72	18.37
p-Xylene	5.61	10.60
o-Xylene	2.20	4.17
Ethylbenzene	2.70	5.11
Styrene	0.10	0.19
Xylene (all isomers)	17.53	33.14

Operational Limits

Quantity	Value	Units
Short-term pumping rate	80	MBbl/hr
Annual throughput	384000	MBbl/yr

Figure 2. Emission Calculations for Hydrocarbon Species

Hydrocarbon Species Emission Rates for Dispersion Modeling

SURROGATE_GROUP	MAX_WT%_HOURLY	MAX_WT%_ANNUAL	ER_lb/hr	ER_tpy
benzene	0.35%	0.29%	35.11	55.33
n-hexane	8.29%	7.25%	830.05	1373.44
methylcyclopentane	1.91%	1.66%	191.20	314.10
cyclohexane	2.12%	1.77%	212.06	334.75
i-butane	13.51%	14.10%	1353.01	2670.06
n-butane	31.01%	30.93%	3105.56	5856.90
n-pentane	22.90%	21.58%	2293.72	4085.99
n-heptane	2.64%	2.14%	264.11	405.82
n-octane	1.07%	0.81%	106.73	153.21
dimethylcyclopentane, all isomers	0.58%	0.45%	57.60	85.41
propylcyclopentane	0.56%	0.45%	56.39	86.15
methylcyclohexane	2.00%	1.61%	200.72	304.72
1t,3-dimethylcyclopentane	0.36%	0.30%	35.88	56.67
1c,3-dimethylcyclopentane	0.33%	0.27%	32.76	51.42
xylene	0.17%	0.12%	16.82	23.36
toluene	0.34%	0.27%	33.73	50.44
cyclopentane	1.14%	1.03%	113.77	194.91
n-nonane	0.32%	0.23%	32.01	44.32
n-propylcyclopentane	0.080%	0.060%	8.00	11.42
i-propylcyclopentane	0.057%	0.043%	5.72	8.15
Styrene	0.001%	0.001%	0.07	0.10
3c-ethylmethylcyclopentane	0.014%	0.010%	1.38	1.98
ethylcyclopentane	0.059%	0.047%	5.96	8.96
3t-ethylmethylcyclopentane	0.011%	0.009%	1.15	1.65
1,1-methylethylcyclopentane	0.007%	0.005%	0.71	1.03
alkenes, generic, not otherwise specified	0.011%	0.007%	1.06	1.33
1-octene	0.004%	0.003%	0.39	0.55
ethylbenzene	0.027%	0.019%	2.65	3.62
i-butylcyclopentane	0.001%	0.001%	0.14	0.19
propane	43.67%	45.47%	4374.33	8609.37
ethane	6.23%	5.08%	624.14	961.16

Section 5
Applicability of CAA § 112(g)

5.1 Introduction

EPA regulations at 40 CFR § 63.42(c) require a person who proposes to construct a new major source of HAP to obtain a case-by-case MACT determination if the proposed major source has not "*been specifically regulated or exempted from regulation under a standard issued pursuant to 112(d), section 112(h), or section 112(j)*" of the Clean Air Act. The purpose of the present section is to show that the proposed facility has not been specifically regulated under any source-specific CAA § 112 standard, and is therefore required to obtain a case-by-case MACT determination.

The listed source category most similar to the proposed facility is the "marine tank vessel loading operations" source category, currently subject to regulation under 40 CFR Part 63, Subpart Y ("MACT Y"). MACT Y emission standards apply during "marine tank vessel loading operations," a term whose meaning derives from several related definitions at 40 CFR § 63.561, summarized below in Table 5-1 (emphasis added):

Table 5-1 Relevant MACT Y Terminology

Term	Definition
Marine tank vessel loading operation	any operation under which a commodity is bulk loaded onto a marine tank vessel from a **terminal**, which may include the loading of multiple marine tank vessels during one loading operation. Marine tank vessel loading operations do not include refueling of marine tank vessels.
Terminal	all **loading berths** at any land or sea based **structure(s)** that loads liquids in bulk onto marine tank vessels.
Loading berth	the loading arms, pumps, meters, shutoff valves, relief valves, and other piping and valves necessary to fill marine tank vessels. The **loading berth** includes those items necessary for an offshore loading terminal.
Offshore loading terminal	a location that has at least one **loading berth** that is 0.81 km (0.5 miles) or more from the shore that is used for mooring a marine tank vessel and loading liquids from shore.

According to these definitions, a marine tank vessel loading operation must involve a "terminal," which consists of one or more "loading berths" at a "structure." An "offshore loading terminal" is a type of terminal, one of whose loading berths is at least 0.5 miles from shore. Finally, "loading berth," in the context of offshore loading terminals, is defined circularly to include items necessary for an offshore loading terminal.

BWTX believes that the pertinent regulatory terms are vague or ambiguous as they relate to the proposed facility, and that the regulatory text itself does not resolve the question of whether the proposed facility is a "marine tank vessel loading operation." First, the term "loading berth" is underspecified with respect to the "offshore loading terminal" subcategory because of its circularity of reference. Second, the definition of "offshore loading terminal" does not specify any outer distance. And finally, the term "structure" is not defined in the regulation, and its dictionary definition ("a building or edifice of any kind, esp. a pile of building of some considerable size and imposing appearance") [40] does not clearly include an SPM buoy.

Defined terms in MACT Y do not clearly encompass the proposed facility. Therefore, BWTX believes that in order to assess MACT Y applicability, it is necessary to examine the individual facilities used to define the "offshore loading terminal" subcategory in 1995, the types of control technologies considered in establishing the MACT floor for the subcategory, as well as the historical and legal context in which MACT Y was developed and promulgated. This examination supports BWTX's position that MACT Y does not apply to Crude oil export facilities located on the OCS (i.e., those taking place beyond the state seaward boundary, or 9 nautical miles in the case of Texas).[41] Three findings support BWTX's conclusions:

1. The rulemaking did not consider any loading facilities located on the OCS.

2. If they existed today, none of the controlled facilities considered during the rulemaking would constitute a "similar source" under 112(g) principles of MACT determinations.

[40] Oxford English Dictionary. 2nd Edition.

[41] Cf. the definition of "boundaries" in the Submerged Lands Act, § 2(b) (43 U.S.C. § 1301(b)).

3. Offshore oil loading facilities in existence at the time facilitated movement of oil produced in California waters where no pipeline connection to shore was available. No high-throughput export facilities existed at the time MACT Y was developed, and they could not have existed given legal restrictions on the export of crude oil in effect at the time.

5.2 Offshore sources considered in establishing MACT Y

In order to identify offshore loading terminals considered in developing MACT Y, BWTX conducted a detailed review of the associated rulemaking docket (legacy rulemaking docket A-90-44).[42] Since the docket does not contain all relevant details about individual offshore terminals, review of the docket was supplemented by considering government publications pertaining to specific marine terminals (or to marine terminals in general), as well as newspaper reports and the published statements of terminal owners and operators.

The MACT Y rulemaking docket indicates that EPA began work on developing a tank vessel emissions standard in 1990, prior to passage of the Clean Air Act Amendments in 1990.[43] Before 1993, EPA had intended to "*address all tank vessel emissions in a comprehensive, multi-faceted manner under Section 183(f)*"[44] rather than under the NESHAP program. Subsequently, however, EPA published notice that it had changed its position and would regulate marine vessel loading operations under CAA § 112 as well as under § 183(f), consistent with the terms of a proposed consent decree.[45]

The earliest mention of the offshore terminals in the MACT Y docket are EPA staff notes from a July 24, 1991, meeting between EPA and representatives of Chevron.[46] Materials presented by Chevron indicated that it operated loading terminals at three offshore locations in the United States. The notes include a description of the facilities consistent with a spread mooring system, a recitation of

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[42] In the following discussion, docket items are referred to by their document ID. The author, title, and date of each document is recorded in the associated docket sheet, available at https://www.regulations.gov/document?D=EPA-HQ-OAR-2003-0198-0002.

[43] A-90-44 II-A-18.

[44] 57 Fed. Reg. 31576, 31586. July 16, 1992.

[45] 58 Fed. Reg. 60021. November 12, 1993.

[46] A-90-44 II-E-35. Except where context dictates otherwise, common names such as "Chevron" are used in this application to refer to business entities and their affiliates, rather than the actual legal names of specific entities (e.g., Chevron USA Inc.).

technical difficulties associated with the use of a subsea vapor recovery pipeline (namely liquid condensate formation), and an apparent suggestion by Chevron that terminals of this type would not be constructed in the future ("*regulation not require controls, but grandfather old ones, not allow new ones*"). The notes additionally identify the locations of four offshore terminals, and a comment that a comprehensive list could be obtained from USCG.

In an August 30, 1991, follow-up letter to EPA, Chevron submitted a list of sixteen "offshore terminals with subsea lines."[47] The list includes all of the locations listed in a March 13, 1995, public comment submitted by Chevron,[48] which was one of two public comments that EPA identified as its source of information for setting the MACT floor for offshore loading terminals.[49] EPA relied heavily on information submitted by Chevron in developing the MACT floor analysis for the offshore loading terminal subcategory. The offshore terminals identified by Chevron are listed below in Table 5-2. Chevron's list has been supplemented with an indication of the mooring geometry, the type of operations conducted (loading vs. unloading), and the years during which each terminal was operated.

[47] A-90-44 II-E-37.

[48] A-90-44 IV-D-136.

[49] Cf. A-90-44 IV-B-2, sec. 4.2. The other was a comment from BAAQMD, discussed below.

Table 5-2 Offshore Terminals with Subsea Lines Mentioned in MACT Y Docket

Location	Distance from Shore	Type	Facility Served	Cargo loaded/unloaded	Years in Operation
Drift River, AK[50]	1.8 miles[51]	Platform	Onshore oil production (tanker across Cook Inlet)	Loading oil	Decommissioning scheduled for 2019.[52]
Hercules, CA	0.6 miles[53]	Platform	Refinery	Product Loading	Refinery closed 1995, limited terminal operation until 1997.[54]

[50] Alaska Department of Environmental Conservation (ADEC). September 16, 2016. Statement of Basis, Permit No. AQ0190TVP03, issued to Cook Inlet Pipe Line Company.

[51] Satellite imagery dated August 27, 2016 at 60° 33′ 23.45″ N, 152 08 25.32 W. Via Google Earth.

[52] The Regulatory Commission of Alaska. March 8, 2019. Order Granting Applicatoin, In the Matter of the Application Filed by COOK INLET PIPE LIEN COMPANY for Approval to Permanently Discontinue Use of and Abandon Drift River Terminal and Tank Farm, Christy Lee Platform, and Drift River Segment and for Approval to Access DR&R Fund. P-18-009, Order No. 4: Finding Use of Facilities no Longer Required, Issuing Construction Permit, Authorizing Access to DR&R Fund, Requiring Filing, and Redesignating Commission Panel.

[53] Satellite imagery dated July 5, 1993, at 38° 03′ 15.62″ N, 122° 16′ 21.69″ W, via Google Earth.

[54] California Energy Commission. California Oil Refinery History. Accessed April 15, 2019, at https://www.energy.ca.gov/almanac/petroleum_data/refinery_history.html.

Location	Distance from Shore	Type	Facility Served	Cargo loaded/unloaded	Years in Operation
Moss Landing, CA	0.8 miles[55]	Multi-buoy[56]	Electric Utility	Unloading fuel oil[57]	Fuel oil no longer fired.[58]
Estero Bay, CA (Chevron)	0.5 miles, 0.6 miles[59]	Multi-buoy[60]	Offshore oil production	Loading oil[61]	Ceased operations in 1999.[62]
Morro Bay, CA (PG&E)[63]	0.7 miles[64]	Multi-buoy	Electric Utility	Unloading fuel oil	Ceased unloading operations in 1990.

55 County of Monterey, California. n.d. Moss Landing Community Plan. Accessed April 17, 2019 at http://www.co.monterey.ca.us/planning/Long-range-planning/Moss_Landing_Community_Plan/Moss_Landing_Community_Plan.pdf. At 89.

56 U.S. Dept. of the Interior. April 1974. Final Environmental Impact Statement. Deepwater Ports: TO accompany legislation to authorize the Secretary of the Interior to regulate the construction and operation of deepwater port facilities (henceforth "DWPA EIS"). at I-24.

57 California Coastal Commission. 1988. Oil and Gas Activities Affecting California's Coastal Zone. at 57.

58 "State releases cleanup plan for Moss Landing power plant." The Mercury News. March 30, 2010. Accessed April 15, 2019, at https://www.mercurynews.com/2010/03/30/state-releases-cleanup-plan-for-moss-landing-power-plant/.

59 California Coastal Commission. August 27, 1999. Item Number W-14a. Revised Findings. Application File No. E-98-26. Chevron Pipeline Company. At 8 (describing the locations of two loading berths).

60 DWPA EIS at I-24.

61 A-90-44 II-E-40.

62 California Coastal Commission. August 27, 1999. Item Number W-14a. Revised Findings. Application File No. E-98-26. Chevron Pipeline Company.

63 DWPA EIS at I-24.

64 California State Lands Commission. February 2018. Initial Study/Mitigated Negative Declaration. Dynegy Morro Bay, LLC Morro Bay Power Plant Marine Terminal Decommissioning Project. at 1-3–1-4. (Report cover depicts aerial photograph of mooring buoys and tanker.)

Location	Distance from Shore	Type	Facility Served	Cargo loaded/unloaded	Years in Operation
Gaviota, CA	0.7 miles[65]	Multi-buoy	Offshore oil production	Loading oil	Built in 1988. Operated 8/1/93–1/31/94.[66]
Goleta, CA[67]	0.5 miles[68]	Multi-buoy	Offshore oil production	Loading oil	Ceased operations in 2012.
Point Conception, CA[69]	0.4 miles[70]	Multi-buoy	Offshore oil production	Loading oil	Last barge loaded in 1987. Abandoned as of 1993.
Mandalay Beach, CA[71]	1.0 miles	Multi-buoy	Electric Utility	Unloading fuel oil	Last barge loaded in 1991.

[65] California State Lands Commission. April 28, 1993. Calendar Item 47 concerning Lease PRC 7075. Authorization to Issue Industrial Lease for Offshore Marine Terminal.

[66] Chevron Corporation. SEC Form 10-K (annual report) for period ending March 31, 1993. March 25, 1994.

[67] County of Santa Barbara. March 2011. Draft Environmental Impact Report for the Ellwood Pipeline Company Line 96 Modification Project. Santa Barbara County EIR No. 09EIR-00000-00005.

[68] Satellite imagery dated November 28, 2006 at 34° 24′28.50″N, 119° 53′23.15″W. Via Google Earth.

[69] County of Santa Barbara Planning and Development. Energy Division. Unocal Point Conception Decommissioning Project. Accessed April 4, 2019 at http://www.sbcountyplanning.org/energy/projects/unocalPtConception.asp.

[70] Padre Associates, Inc. 2002. Current Marine Terminal Decommissioning Projects. Environmental Issues and Project Responses. Accessed April 15, 2019 at https://web.archive.org/web/20181130073234/https://www.slc.ca.gov/About/Prevention_First/2002/Decommissioning-Current.pdf.

[71] Ibid.

Location	Distance from Shore	Type	Facility Served	Cargo loaded/unloaded	Years in Operation
El Segundo, CA	1.4– 1.5 miles[72]	Multi-buoy[73]	Refinery	Unloading oil, loading product	In operation.
Huntington Beach, CA	1.4 miles[74]	Multi-buoy	Refinery	Unloading oil, loading product	Refinery closed in 1991.[75]
Carlsbad, CA[76]	0.5 miles	Multi-buoy	Electric Utility	Unloading fuel oil	Plant conversion to gas prior to 1990, abandoned c. 1999.
Barbers Point, HI (Chevron)	1.4 miles[77]	Multi-buoy	Refinery	Unloading oil, loading product.[78]	Refinery closed in 2018,[79] partial transfer of assets to neighboring refinery.

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72 South Coast Air Quality Management District. October 30, 2018. Facility Permit to Operate issued to Chevron Products Co. Facility ID 80030. Revision # 88. At 142–143 (referring to three berths).

73 Satellite imagery dated November 2, 2005 at 33° 54′ 15.26″ N, 118° 27′ 08.01″ W. Via Google Earth.

74 Coast Guard California Spill Report Stirs Fuss. July 2, 1990. Oil & Gas Journal.

75 "Shutting Down: Golden West Refinery Closure will Cost 280 their Jobs." December 22, 1991. Los Angeles Times. Accessed April 15, 2019 at https://www.latimes.com/archives/la-xpm-1991-12-22-hl-1372-story.html.

76 California State Lands Commission. December 2015. Mitigated Negative Declaration. Cabrillo Power I LLC Encina Marine Oil Terminal Decommissioning Project.

77 Satellite imagery dated January 29, 2013 at 21° 16′ 40.68″ N, 158° 04′ 18.99″ W. Via Google Earth.

78 A-90-44 II-E-35 ("*mainly receiving*").

79 "Island Energy to end Hawaii refining business, sell assets." August 31, 2018. Oil and Gas Journal.

Location	Distance from Shore	Type	Facility Served	Cargo loaded/unloaded	Years in Operation
Barbers Point, HI (Hawaiian Ind. Ref.)[80]	1.5 miles[81]	SPM	Refinery	Unloading oil, loading product	In operation
River Head, NY[82]	1.3 miles[83]	Platform	Bulk terminal	Product loading and unloading	In operation
Port Fourchon, LA (LOOP)	20 miles[84]	SPM	Deepwater Port	Unloading oil (prior to 2018), loading and unloading oil (since 2/18/2018).[85]	In operation

80 The Natural Resource Trustees for the Tesoro Oil Spill, Hawaii. November 2000. Final Restoration Plan and Environmental Assessment for the August 24, 1998 Tesoro Hawaii Oil Spill (Oahu and Kauai, Hawaii).

81 Par Pacific Holdings, Inc. March 11, 2019. SEC Form 10-K for reporting period ending 12/31/2018. ("*On Oahu, the system begins with our SPM located 1.7 miles offshore of our Hawaii refinery. This SPM allows for the safe, reliable, and efficient receipt of crude oil shipments to the Hawaii refinery, as well as both the receipt and export of finished products.*")

82 New York State Department of Environmental Conservation. April 12, 2016. Permit Review Report. Permit ID 1-4730-000023/00030. Issued to United Riverhead Terminal Inc.

83 Satellite imagery dated March 6, 2012 at 41° 00′01.51″N, 72° 38′47.83″W. Via Google Earth.

84 Satellite imagery dated March 12, 2013 at 28 51 45.06 N, 90 01 26.29 W. Via Google Earth.

85 "First exported VLCC from Louisiana Offshore Oil Port arrives in China: In the LOOP." April 24, 2018. S&P Global Platts. Accessed April 15, 2019 at https://blogs.platts.com/2018/04/24/vlcc-loop-export-arrives-china-loop/.

EPA staff notes from an April 20, 1994, meeting with representatives of TOSCO refer to the list provided by Chevron and its relevance to setting the MACT floor:

> *Mr. Markwordt stated that anecdotal data mentioned during the Chevron meeting indicated that there were approximately 16 offshore terminals in the U.S. At least 3 of these offshore terminals appeared to have installed emissions controls*.[86]

Because Chevron's 1991 letter did not identify specific control measures undertaken at any of the listed terminals, it is presumed that EPA staff reviewed the list and made inquiries into the specific control measures in practice. Terminals which practiced unloading only (LOOP and the four electric utilities) would not have had any loading emissions. The three controlled terminals referred to are most likely the following:

- Pacific Refining operated a refinery in Hercules, CA, prior to 1995. The loading platform would have been subject to BAAQMD Rule 8-44. Although the exact nature of the control system has not been identified, Chevron's 1995 comment letter states that it was "similar to a wharf-type terminal where the vapor control equipment is installed on the platform itself."[87] BWTX believes this facility is the "platform" referred to in BAAQMD's 1995 comment letter.[88]
- The Ellwood Marine Terminal (EMT), located in Goleta, CA, served to transport to market crude oil that was produced offshore at Platform Holly (in California coastal waters) and treated at an onshore processing facility. Chevron's 1995 comment letter remarked that EMT was "served by a barge that has its own vapor control equipment." This remark appears to refer to the use of a dedicated fleet of controlled tankers, rather than an emissions-controlling workboat of the type described in its June 25, 1992, presentation to EPA.[89] In order to comply with Santa Barbara APCD Rule 327, only specially-designed vessels with onboard vapor recovery systems (refrigeration-based) were permitted to take on cargo from

[86] A-90-44 II-E-49.

[87] A-90-44 IV-D-136.

[88] A-90-44 IV-D-80.

[89] A-90-44 II-E-40. The presentation concerned a contemplated control project at Chevron's Estero Bay loading terminal, which would eventually become subject to San Luis Obispo County APCD Rule 427.

the terminal. Two ocean-going barges, the *Jovalan* and the *Olympic Spirit*, were used for these purposes.[90]

- The Gaviota Interim Marine Terminal (GIMT), located in Gaviota, CA, was developed to serve a similar function to EMT. It was intended to replace a prior multi-buoy offshore terminal operated by Getty Oil, and would transport oil produced at the Point Arguello field (offshore in federal waters) which had been processed at an onshore plant. GIMT was also subject to Santa Barbara APCD Rule 327, and was designed with a vapor control system based on the use of subsea vapor lines that carried VOC vapors to an onshore recovery system. Two 10 ¾"–12" polyethylene vapor lines were installed in a loop to allow for pigging (necessary to remove liquid condensate). The vapor return lines traveled approximately 3500 ft. under water to the onshore portion of the terminal.[91] The MACT Y docket contains correspondence between USCG and Chevron discussing the difficulties in handling liquid condensate formed in the vapor recovery line,[92] as well as a presentation from Chevron noting that such lines were "extremely difficult to permit."[93]

  The comment about difficulties likely refers to the ordeals faced by companies interested in developing the Point Arguello field (including Chevron) and operating GIMT. Due to conflicts with the California Coastal Plan (which generally discouraged tankering of crude oil in the Santa Barbara channel), operators experienced delays in receiving the necessary permits to operate the terminal, and the eventual permits required operations to cease on February 1, 1994, if binding agreements for construction of a pipeline were not made.[94] Such agreements were not timely made, and the terminal ceased operations after only six months. Chevron argued for exclusion of this source in its 1995 comment letter to EPA, noting that "the terminal does not have permission to tanker."[95]

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[90] County of Santa Barbara. March 2011. Draft Environmental Impact Report for the Ellwood Pipeline Company Line 96 Modification Project. Santa Barbara County EIR No. 09EIR-00000-00005.

[91] California Coastal Commission. May 23, 1997. Permit Amendment Staff Recommendation. Application File No. E-92-6-A2. Gaviota Terminal Company (GTC). In-place abandonment and/or removal of the offshore components of the Gaviota Interim Marine Terminal.

[92] A-90-44 II-D-49.

[93] A-90-44 II-E-40.

[94] California State Lands Commission. April 28, 1993. Authorization to Issue Industrial Lease for Offshore Marine Terminal (lease block PRC 7075). Calendar Item 47.

[95] A-90-44 IV-D-136.

In a July 8, 1992, letter to EPA, Chevron had suggested a definition of "offshore loading terminal" for the purposes of creating a subcategory for such installations.[96] EPA included subcategorization as an option in its May 13, 1994, Notice of Proposed Rulemaking (NPRM)[97] using a definition based on that suggested by Chevron. The definition contained in the NPRM would have included multibuoy mooring-based terminals, and would have excluded causeway- and jetty-type terminals. Platform-type terminals and SPM's would likely have been included as well, though it's not certain whether they would have qualified as an "open water location."

During the public comment period, owners of causeway-type terminals with loading berths at least 0.5 miles from shore[98] argued that their facilities should be exempt from MACT Y control requirements. Although Chevron had represented its Richmond, CA, "Long Wharf" terminal as an onshore terminal (in contrast to El Segundo), BAAQMD submitted a comment observing that the facility had berths 0.5 miles from shore, was controlled (consistent with Chevron's representations), and should be considered in setting the MACT floor for offshore loading terminals.[99]

On consideration of public comments, EPA revised the definition of the "offshore loading terminal" subcategory to refer to all terminals with at least one loading berth 0.5 miles or more from shore (thus including causeway- and jetty-type terminals). The memorandum to the docket detailing recalculation of the MACT floor for offshore loading terminals indicated that there were "*no more than 20 marine tank vessel loading terminals with subsea lines that are at least 0.5 miles from shore … [none of which] presently control loading emissions*."[100] Since the memorandum specifically identifies Chevron's 1995 comment letter as the source of its information, it appears that EPA accepted Chevron's arguments for disregarding EMT and GIMT in setting the MACT floor (the former did not use controls installed at the terminal itself, and the latter had lost authorization to operate its facility). The memorandum goes on to note that an unknown number of additional offshore terminals

[96] A-90-44 II-D-55. ("*Such a terminal is an open water location for mooring a marine tank vessel and loading either Crude Oil or Gasoline through subsea lines from shore.*")

[97] 59 Fed. Reg. 25004.

[98] E.g., Amerada Hess Corporation, referring to a causeway-type terminal at its St. Croix refinery. A-90-44 IV-D-140.

[99] A-90-44 IV-D-80.

[100] A-90-44 IV-B-2 at 8.

existed, which did not use subsea lines, two of which were known to control emissions. The source of information given is BAAQMD's 1995 comment letter.[101]

To summarize, the MACT Y rulemaking docket shows that EPA began considering the issue of offshore loading terminal as early as 1991, and had a list of specific facilities that would potentially be subject to the rule. The list included sixteen offshore terminals, eleven of which were actually used for loading operations. Of the eleven facilities used for loading, three were of the platform type, seven were of the multi-buoy mooring type, and one was of the SPM type. All loading terminals were located in state territorial waters. Although EPA was aware of control systems that had been designed for two mooring buoy-type terminals, neither control system was considered in setting the MACT floor.

5.3 2011 RTR Rulemaking

MACT Y was amended in 2011 as part of a residual risk and technology review rulemaking.[102] Although existing offshore loading terminals were required to comply with submerged fill standard, at the proposal stage EPA considered requiring add-on controls for offshore loading terminals with gasoline throughputs of 1 MMBbl/yr or greater.[103] The cost analysis supporting the proposed control requirement was subsequently revised[104] and the control proposal was abandoned following consideration of public comments. Of course, offshore loading facilities under consideration at the time were actual facilities (and "model" facilities based on actual facilities) in existence at the time, as one pertinent comment implies:

> *Offshore facilities are typically very large facilities that distribute most or all of their product/crude oil via ships, rather than barges. The result is that offshore facilities have*

[101] The report inaccurately implies that the Hercules, CA loading platform lacked subsea lines. Since BAAQMD did not identify this source by name, it is probable that the contractor drafting the report was not aware of the specific facility being referred to. Also, as noted above, five of the listed terminals did not conduct loading operations.

[102] 76 Fed. Reg. 22596. Apr. 21, 2011.

[103] 75 Fed. Reg. 65068, 65115–65116. Oct. 21, 2010.

[104] David Green and Karen Schaffner (RTI Intl.) to Stephen Shedd (EPA). *Cost Effectiveness and Impacts of Lean Oil Absorption…* Mar. 17, 2011. Docket item EPA-HQ-OAR-2010-0600-0437.

> *many loading berths located on very long piers farther from shore, so that ships large enough to economically distribute the products can berth at them.*[105]

Context suggests that the types of offshore facilities under consideration were of the causeway- or jetty-type. Even though EPA ultimately rejected controls at such facilities as not cost-effective, BWTX does not believe that the 2010–2011 is relevant to assessing the availability of controls for a qualitatively different type of facility that was not in existence at the time.

5.4 Discussion

The history of the development of MACT Y supports the finding that BWTX's proposed project does not belong to the source category covered by that regulation. Two key factors distinguishing BWTX's project from the facilities considered during the MACT Y rulemaking ("MACT Y facilities") are a significantly greater distance from shore (location on the OCS) and significantly greater throughput (use as an export facility). Section 6 of the application demonstrates that none of the MACT Y facilities would constitute a "similar source" as that term is defined at 40 CFR § 63.51. The remainder of this section explains why distance from shore and throughput would have been relevant from the standpoint of defining the source category.

5.4.1 Location on the OCS

The DWPA defines a "deepwater port," in relevant part to

> mean[] any fixed or floating manmade structure other than a vessel, or any group of such structures, that ***are located beyond State seaward boundaries*** and that are used or intended for use as a port or terminal for the transportation, storage, or further handling of oil or natural gas for transportation to or from any State, except as otherwise provided in section 1522 of this title, and for other uses not inconsistent with the purposes of this chapter, including transportation of oil or natural gas from the United States outer continental shelf;

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105 Matthew Todd (API) to Docket. *Comments on EPA's Proposed Rule…* December 6, 2010. Docket item EPA-HQ-OAR-2010-0600-0359.

(B) includes all components and equipment, including pipelines, pumping stations, service platforms, buoys, mooring lines, and similar facilities ***to the extent they are located seaward of the high water mark***;

…

(D) ***shall be considered a "new source" for purposes of the Clean Air Act*** (42 U.S.C. 7401 et seq.), and the Federal Water Pollution Control Act (33 U.S.C. 1251 et seq.).[106]

The DWPA therefore specifies that a deepwater port is a specific type of "new source" consisting of port or terminal facilities located beyond the "state seaward boundaries," which are, at a minimum, three nautical miles from shore.[107] The deepwater port also includes other equipment located seaward of the high water mark. In other words, the DWPA defines a specific type of source for purposes of the Clean Air Act, none of whose components are located on land.

In contrast, section 183(f) of the Clean Air Act, whose implementation ultimately led to promulgation of MACT Y, directs EPA to consider, to the extent practicable, only those emissions standards that would apply to "loading and unloading facilities and not to tank vessels."[108] Consequently, when developing its proposed regulations, EPA explicitly stated its intent for control requirements to apply to terminals, rather than to individual vessels.[109] Consistent with this direction, and as noted above, one offshore facility achieving control by limiting loading to barges with onboard control systems was disregarded when setting the MACT floor for offshore loading terminals.

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[106] 33 USC § 1502(10) (emphasis added).

[107] *See* 33 USC § 1518 (noting that the nearest adjacent coastal state is the state "whose seaward boundaries if extended beyond 3 miles, would encompass the site of the deepwater port). The Submerged Lands Act grants to Texas and Florida the submerged lands within three marine leagues, which is nine nautical miles, off the Gulf coast, whereas other states received such lands only out to three nautical miles. *See United States v. Louisiana*, 363 U.S. 1, (1960); *United States v. Florida*, 363 U.S. 121, 129 (1960). In 1995, the DWPA language demarcating the geographic jurisdiction of the Act was somewhat different. That version of the statute defined a "deepwater port" as one "located beyond the territorial sea and off the coast of United States …" (33 USC §1502 (10) (1995 ed.). The provision of the DWPA, however, clarifying the three miles geographic jurisdictional limit for the nearest adjacent coastal state was three miles in 1995 and remains so today. 33 U.S.C. § 1518.

[108] CAA § 183(f)(1)(A). The Committee Report for the House Version of the Clean Air Act Amendments of 1990 explains that "*[t]he emphasis on loading and unloading facilities is intended to minimize problems that might be created by subjecting vessels to inconsistent requirements at different ports.*" House Report 101-490 at 254–255.

[109] 59 Fed. Reg. 25009. May 13, 1994.

While deepwater ports, by definition, exclude all land-based equipment, the MACT Y "offshore loading terminal" subcategory was developed with a primary emphasis on land-based control systems. As comments in USCG's companion rulemaking make clear, the regulations responded in part to a proliferation of control requirements issued by State air pollution control agencies.[110] State regulation of marine vessel emissions was cited as a concern which ultimately led to development of national emission standards by EPA.[111] BWTX believes that the absence of any discussion of MACT Y as it pertained to DWPA sources is consistent with an assumption that the regulations were only intended to apply within state territorial waters (i.e., "offshore loading terminal" and "deepwater port" have non-overlapping meanings). This is consistent with EPA's reasoning in excluding lightering operations from the affected source category (they "do not take place at onshore terminals"[112]).

5.4.2 Non-export OCS facilities

In addition to offshore loading operations subject to the Deepwater Ports Act, there also exist offshore loading operations that are regulated under the Outer Continental Shelf Lands Act (OCSLA).[113] OCSLA applies primarily to exploration, development and production of minerals from submerged lands and sea beds beyond state seaward boundaries, and generally requires that the laws of the United States apply on the Outer Continental Shelf in the same manner as they would to activities located on land.

OCSLA operations include floating production, storage, and offloading (FPSO) units which load crude oil onto tankers. Two such units are known to currently operate in the Gulf of Mexico.[114] While the MACT Y definition of "source" excludes "offshore drilling platforms" it is not immediately obvious that this exclusion should apply to FPSO's: FPSO's are not platforms and they are not used for drilling.[115] FPSO's would not qualify for the "lightering operations" exclusion either, since they do not transport

[110] 55 Fed. Reg. 25396. June 21, 1990 (*"[s]ome states … have issued requirements for the control of [VOC] emissions from tank vessels…"*); Id. at 25407 (*"…these types of facilities [i.e., loading at mooring buoys] present some unique problems … [h]owever, exempting them from the regulation is not possible since some states may require offshore terminals to collect cargo vapors emitted from vessels within their jurisdictional waters."*)

[111] 59 Fed. Reg. 25005.

[112] *Id*. at 25007.

[113] 43 U.S.C. § 1331 et seq.

[114] These are the *BW Pioneer* and the *Turritella*.

[115] BWTX cannot locate any rationale for the exclusion of offshore drilling platforms in the rulemaking docket.

crude oil, and are therefore not "marine tank vessels." Although they are treated as "points in the United States" for purposes of the Jones Act, they do not load liquids from shore, and would likely not qualify as "offshore loading terminals" under MACT Y.

FPSO's conduct loading operations, and are similar to Deepwater Ports in several respects.[116] For example, the "Offshore Storage & Treatment" (OS&T) facility, operated by Exxon Corporation from 1981–1993 (the first FPSO located in U.S. waters),[117] received produced oil through a single point mooring buoy (SALM-type) and loaded processed oil onto a tandem-moored tanker. Since OS&T was located beyond California's seaward boundary, confusion existed as to whether it should be subject to the Deepwater Ports Act, with the issue of non-applicability eventually being settled by the courts.[118]

It is presumed that EPA was aware of the OS&T source at the time MACT Y was being developed, and that EPA intended to exempt OS&T and similar sources from the regulation. EPA issued a determination in 1978, finding that PSD permitting and California SIP requirements applied to OS&T.[119] The decision was eventually reversed in court due to a jurisdictional conflict between EPA and the Interior Department.[120] Congress addressed the issue during passage of the Clean Air Act Amendments of 1990 by inserting what is now Section 328 of the Clean Air Act. Under this provision, EPA has authority to enforce Clean Air Act regulations, including the SIP of the nearest coastal state, except for in portions of the Gulf of Mexico (including areas offshore of Texas). The level of attention that it attracted suggests that EPA was reasonably aware of the source and its operations. Finally, the source is mentioned in the National Research Council report that is contained in the MACT Y docket[121] and mentioned as a key step towards the development of EPA's rule.[122]

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[116] In fact, MARAD regulations contemplate the refurbishment of OCSLA equipment for use as a deepwater port (33 CFR § 148.105(s)).

[117] ExxonMobil Corp. History of the Santa Ynez Unit. Accessed April 3, 2019 at https://www.syu.exxonmobil.com/history.

[118] *Get Oil Out! Inc. v. Exxon Corp*. 586 F.2d 726 (CA9 1978).

[119] 43 Fed. Reg. 16393. April 18, 1978.

[120] *California v. Kleppe*. 604 F.2d 1187 (CA9 1979).

[121] A-90-44 II-I-4.

[122] 59 Fed. Reg. 25005. May 13, 1994.

BWTX believes that an intent to exempt sources outside of state jurisdictional waters explains the lack of information useful to discern how MACT Y should be applied to sources covered by the Deepwater Ports Act and the OCSLA. For example, BWTX cannot identify any comment about differential application of MACT Y to OCSLA offshore loading operations where EPA's jurisdiction varies according to CAA § 328. It is also unclear whether production platforms and/or FPSO's were intended to fall under the "offshore drilling platforms" or "lightering operations" exclusions. Finally, BWTX cannot identify any discussion of EPA's proposed half-mile test for source aggregation, and how it should be applied at deepwater ports using multiple mooring buoys separated by more than 0.5 miles from each other. The simplest explanation for the lack of information in the docket is that the regulation was never intended to apply to facilities specifically regulated by DPA and OCSLA (i.e., facilities outside of state jurisdictional waters). This is consistent with several other facts detailed above: No loading terminals in federal waters were considered, though at least one existed.[123] Onboard-type control systems were specifically excluded from consideration, even though this is the most plausible means of control for a terminal far from shore (cf. discussion in Secs. 6–7). And finally, an important overall objective of the rulemaking was to standardize equipment at marine terminals subject to a variety of *state-level* control requirements.

5.4.3 Crude Oil Export Facilities

The Deepwater Ports Act was originally promulgated to address the siting of crude oil *import* terminals that could accommodate deep draft "supertankers," or VLCCs. LOOP is currently the only Deepwater Port facility that *exports* crude oil.

MACT Y facilities reviewed above were nearshore operations for handling relatively small volumes for coastwise trade. None of these facilities were used for the export of crude oil. Such exports were generally prohibited under Section 103 of the Energy Policy and Conservation Act of 1975,[124] which was repealed on December 18, 2015.[125] Therefore, the source category corresponding to BWTX's

[123] In addition to OS&T, other offshore loading operations are referred to in *GOO v. Exxon*: a letter from USCG is excerpted in the opinion, reading in part:

> *Indeed, as you are aware, there are a number of permanently moored barges in the Gulf of Mexico on the U.S. continental shelf which function exactly in the manner that you intend to employ off Santa Barbara, and have done so for several years.*

[124] P.L. 94-163 (89 Stat. 871, 877). Dec. 22, 1975.

[125] P.L. 114-113 (129 Stat. 2242, 2987). Dec. 18, 2015.

proposed facility (crude oil export facility) could not have existed at the time MACT Y was developed, and is not reasonably covered by the defined terms in MACT Y.

Section 6
Similar Source Analysis

6.1 Introduction

A new major source of HAP must comply with a level of control that is at least as stringent as that achieved by the best-controlled existing similar source. The similar source analysis therefore consists of identifying all existing similar sources along with the level of HAP reduction achieved at each, ranking them by order of effectiveness, and selecting the most effective option. This represents the MACT floor.

As explained in Section 2, although BWTX's proposed project will not belong to the same source category as facilities that are (or were) subject to MACT Y, such facilities must still be evaluated as potential "similar sources" following the guidance set forth in the 112(g) preamble.

This section consists of two parts. First, a list of potentially similar sources is considered and evaluated following the five-factor test specified in the 112(g) preamble. Second, the level of HAP emissions reduction is determined for sources found to be similar (only one was identified). This level of emissions reduction sets the minimum level of control for BWTX's recommended MACT requirements.

6.2 Identifying "similar sources"

In assessing whether a particular source is a "similar source," The 112(g) preamble specifies five factors that should be considered by permitting authorities: volume and concentration of emissions, type of emissions, similarity of emission points, cost and effectiveness of controls, and other operating conditions.[126]

Two evaluations have been conducted to identify potentially similar sources, and are included in the present section.

[126] 61 Fed. Reg. 68395. Dec. 27, 1996.

- The analysis presented in Table 6-1, below, originally submitted on November 15, 2019. This analysis covers offshore loading facilities identified from the MACT Y docket as well as on the Norwegian Continental Shelf. Table cells corresponding to a particular factor are shaded green if the source in question is similar to the proposed facility with respect to that factor, and are shaded red in the case of a significant dissimilarity. Unshaded cells correspond to dissimilarities that are not judged to be decisive in determining whether the two sources are similar. The table also indicates whether control is currently achieved, and whether the source is located in the United States.[127]

- An analysis considering additional sources and providing additional details about sources mentioned in Table 6-1, originally submitted on December 13, 2019.

6.2.1 Sources considered in November 15, 2019, analysis

[127] Cf. Id. at 68394 ("*The definition of MACT for new source MACT in this rule does not require consideration of sources outside the U.S.*").

Table 6-1 Application of 112(g) "similar source" guidance to MACT Y sources

Potentially Similar Source	Control Technique Employed	Source in Operation? Achieves Emissions Reductions in Practice? Achieved in US?	Volume and concentration	Type of emissions	Similarity of emission points	Cost and effectiveness of Controls	Comparable operating conditions	Overall differences from BWTX's project	Similar Source?
Gaviota Interim Marine Terminal (GIMT)	Spread mooring system contained subsea vapor recovery pipelines which directed loading vapors to shoreside control system.	Currently does not exist. Operated for six months in 1993–1994. Emissions reduction not demonstrated.	Similar concentration (crude oil vapors). Volume is lower and intermittent.	Same (crude oil vapors)	Smaller tanker vessel, more infrequent loadings.	Involved capture system routing vapors to onshore control device. Effectiveness not established, and costs would not be comparable due to differences in distance from shore.	Ocean conditions and mooring geometry differ. Loaded vessel does not weathervane.	BWTX will load crude oil onto deep-draft VLCC's for export, and will be connected to shore with a 25 mi. pipeline. BWTX's facility will operate on a frequent basis with high throughputs. GIMT was used for tankering small volumes of crude oil produced offshore to markets along the California coast. Throughputs were limited to oil produced in the Point Arguello field. The terminal never operated on a sustained basis and the control system was not demonstrated in practice.	No

Potentially Similar Source	Control Technique Employed	Source in Operation? Achieves Emissions Reductions in Practice? Achieved in US?	Volume and concentration	Type of emissions	Similarity of emission points	Cost and effectiveness of Controls	Comparable operating conditions	Overall differences from BWTX's project	Similar Source?
Louisiana Offshore Oil Port (LOOP)	Submerged fill.	Began loading crude oil onto VLCC's in February 2018.	Similar concentration (crude oil vapors).	Same (crude oil vapors)	Deep-draft vessel (VLCC) with high throughputs loaded via SPM.	Similar cost and effectiveness based on distance from shore and type of loading facility.	LOOP uses a platform for pumping and administration, but otherwise operations are similar.	BWTX's facility will be similar to LOOP in terms of the types of vessels served, the levels of throughput, and the ability to control emissions. The main different is the presence of a platform at LOOP. Since the platform is existing and was not designed to accommodate vapor recovery systems, and LOOP has not proposed to install any vapor controls, retrofit considerations are not known.	Yes
Riverhead, NY	A study discussing installation of controls on a platform was provided to the MACT Y docket.	Source in operation, but add-on controls were never installed.	Similar concentration, lower volumes (refined products for regional market).	Similar (refined product vapors).	Shallow draft tanker vessels, more infrequent loadings. Loading is via "sea island"-type dock and not via mooring buoy.	Because vessels do not weathervane, a platform (not involving subsea lines) was considered as near as 30 m to the loading berth. Liquid condensate / backpressure issue would not have been as significant. Personnel access would have already been available for main platform.	Ocean conditions and mooring geometry differ. Loaded vessel does not weathervane. Loading not via mooring buoy.	BWTX will use SPM buoys to load VLCC's. SPM buoys allow the loaded vessel to weathervane, significantly increasing the distance from the loading connection to any control device.	No

Potentially Similar Source	Control Technique Employed	Source in Operation? Achieves Emissions Reductions in Practice? Achieved in US?	Volume and concentration	Type of emissions	Similarity of emission points	Cost and effectiveness of Controls	Comparable operating conditions	Overall differences from BWTX's project	Similar Source?
Chevron El Segundo, CA	Workboats are used to recover emissions from bunker fuel loading operations.	Currently in operation and achieving emissions reductions.	Significantly lower concentration (gasoil vapors).	Similar (gasoil vapors).	Workboat moors adjacent to spread-moored tanker vessel.	Vapor processing rate approximately 1/100th of what required for BWTX's operations.	Ocean conditions and mooring geometry differ. Loaded vessel does not weathervane.	Using workboats at BWTX's facility would require a significantly higher vapor processing capacity (approximately 100 times) VLCC's at BWTX's facility will not be spread-moored, making it more difficult for workboat to maintain position. Based on vapor processing capacity and positioning issues, applying this control technique to BWTX's facility would prevent it from operating continuously and satisfying its contractual obligations.	No
Chevron El Segundo, CA	Control device onboard loaded vessel.	Yes.	Similar concentration (crude oil vapors), lower volume.	Same (crude oil vapors).	Physically similar (handymax-sized crude oil tanker), but vessels are a captive fleet controlled by terminal owner.	Installed cost is proportional to number of ships in fleet (i.e., 30–60 times higher for high throughput export terminal).	Ocean conditions and mooring geometry differ.	BWTX will not control the fleet of VLCC's calling at its terminal. It is not economically feasible to ensure that all loaded vessels are retrofitted with onboard emissions control equipment.	No
Ellwood Marine Terminal	Control device onboard loaded vessel.	Ceased operation in 2012.	Similar concentration, volume lower and intermittent.	Same (crude oil vapors).	Smaller tanker vessel, more infrequent loadings. Vessels are a captive fleet controlled by terminal owner.	Installed cost is proportional to number of ships in fleet (i.e., 30–60 times higher for high throughput export terminal).	Ocean conditions and mooring geometry differ.	BWTX will not control the fleet of VLCC's calling at its terminal. It is not economically feasible to ensure that all loaded vessels are retrofitted with onboard emissions control equipment.	No

Potentially Similar Source	Control Technique Employed	Source in Operation? Achieves Emissions Reductions in Practice? Achieved in US?	Volume and concentration	Type of emissions	Similarity of emission points	Cost and effectiveness of Controls	Comparable operating conditions	Overall differences from BWTX's project	Similar Source?
North Sea Shuttle Tankers (various locations in North Sea)	Control device onboard loaded vessel.	Demonstrated, but not achieved in United States.	Similar concentration (crude oil vapors) and volume, but less frequent loadings at any given off-take location.	Same (crude oil vapors).	Physically similar (Suezmax-sized shuttle tanker), but vessels were a captive fleet with restricted service area.	Installed cost is proportional to number of ships in fleet (i.e., 30–60 times higher for high throughput export terminal).	Similar volumes, (off-take of approximately 1 MMBbl from offshore production are).	BWTX will not control the fleet of VLCC's calling at its terminal. It is not economically feasible to ensure that all loaded vessels are retrofitted with onboard emissions control equipment.	No
Richmond Long Wharf, CA	Control device located near shoreside terminal.	Yes.	Similar in concentration and volume.	Similar (refined product vapors).	Loading arm, fixed vapor return line and dockside vapor skid are employed.	Cost-effective capture system and controls can be located on or near the dock.	Fixed dock or platform available for construction of capture and control equipment, installation of utilities. No need to employ subsea vapor recovery pipelines. Can use onshore utilities.	BWTX's facility is not onshore or nearshore. It is not possible (physically or within safety constraints) to locate control systems on the SPM buoy.	No

6.2.2 Sources considered in December 13, 2019, analysis

Limetree Bay Terminals SPM

Limetree Bay Terminals, LLC received a permit in April 2018 to modify its existing marine loading docks, including installation of a single point mooring (SPM) to allow vessels to load and unload at maximum draft.[128] According to the permit application, the SPM is connected to shore by 5800 linear feet of offshore piping, and loading of crude oil at high throughputs (up to 127 MMBbl/yr) may take place. The application states that vessels to be loaded at the SPM may have drafts of up to 76 feet (i.e., VLCC's may be loaded). The permit does not require add-on controls for loading operations at the SPM, and it is presumed that they will be controlled using bottom fill and other operational practices.

Based on this information, the Limetree Bay SPM would have similar emission points, similar volume and concentration of emissions, and generally comparable operating conditions. Although the sources does not employ add-on controls, and it is therefore not possible to conclude whether they are technically feasible, such add-on controls would be less costly and more effective than comparable controls applied to BWTX's project. Due to the proximity to shore (1 mile of offshore piping vs. 25 miles of offshore piping), captured vapors from the Limetree Bay SPM could potentially be processed at a shoreside control device, making it unnecessary to construct an offshore platform. The cost and feasibility of bottom-fill and other operational practices, however, are not strongly dependent on the distance to shore.

Based on the above considerations, the Limetree Bay Terminals SPM is not a similar source.

Barber's Point SPM

An SPM loading facility is used by Par Hawaii Refining, LLC for unloading of crude oil and for loading of refined products. The SPM is located 1.7 miles offshore, and is connected to a nearby refinery via three undersea pipelines: a 30-inch line for crude oil, and 20- and 16-inch lines for refined products. The SPM is used to transfer refined products throughout the Island of Oahu as well as the

[128] Virgin Islands Department of Planning and Natural Resources. Authority to Construct STX-895-AC-PO-18. April 20, 2018.

neighboring islands of Maui, Hawaii, Molokai and Kauai.[129] AIS data reviewed during preparation of the Case-by-Case MACT application indicates that Suezmax-range vessels have recently called at the SPM, and BWTX presumes that the SPM would be capable of accommodating VLCC's as well. Based on the absence of vapor recovery pipelines mentioned in any description of the system and a review of photographs of the SPM, it is presumed that add-on controls are not used for loading operations. Instead, bottom fill and other operational practices are used during refined product loading operations.

Based on the information reviewed, the Barber's Point SPM has similar emission points to BWTX's proposed facilities, but appears to operate with lower throughputs, since its export operations are primarily focused on supplying refined products for the Hawai'ian islands. Although add-on controls are not employed, and it is therefore not possible to conclude whether they are technically feasible, such controls would likely be less costly and more effective than similar controls applied to BWTX's facility. Due to the nearshore location (1.7 miles from shore), it is possible that controls could be located onshore rather than on a dedicated offshore platform. The cost and feasibility of bottom-fill and other operational practices, however, are not strongly dependent on the distance to shore.

Based on the above considerations, the Barber's Point SPM is not a similar source.

Gaviota Interim Marine Terminal (GIMT)

As noted above, GIMT was a multi-buoy mooring-based loading facility intended to transport oil produced in the Point Arguello field (offshore in federal waters), which had been processed at an onshore plant. GIMT was subject to Santa Barbara APCD Rule 327, and was designed with a vapor control system based on the use of subsea vapor lines that carried loading vapors to an onshore control device. Two 10 3/4" –12" polyethylene vapor lines were installed in a loop to allow for pigging. The vapor return lines traveled approximately 3500 feet under water to the onshore portion of the terminal. The terminal loaded crude oil cargos of approximately 250,000 Bbl (i.e., Handymax-class) three to four times per month beginning in August 1993, but the terminal's California Coastal Commission permit lapsed and it was required to cease operations on February 1, 1994.[130]

[129] U.S. Securities and Exchange Commission (SEC). Form 10-K for Par Pacific Holdings, Inc. Period ending December 31, 2015.

[130] SEC. Form 10-K for Chevron Corporation. Period Ending December 31, 1993.

GIMT used a multi-buoy mooring for loading, so its emission points were different from the proposed BWTX project because loaded vessels did not weathervane. Its loading operations were less frequent and of lower throughput (monthly throughput of approximately 1 MMBbl vs. 32 MMBBl for BWTX). Given the limited access to historical records and the brief period during which operations were sustained, BWTX is unable to verify whether the control system operated effectively during loading operations. Notwithstanding, a similar control system would be more costly and less effective for BWTX's facility. The difference in throughputs would require significant scale-up of the vapor processing capacity, and GIMT's nearshore location (less than one mile) eliminated the need for GIMT to construct an offshore platform to house a control device.

GIMT is not an existing source, and based on the above considerations it would not otherwise qualify as a similar source.

Riverhead, NY Terminal

A platform-type terminal located in Riverhead, NY is used for loading and unloading petroleum and petroleum liquids, including crude oils, distillate oils, and residual oils. Platform-type terminals employ a fixed loading berth. According to the facility's Title V permit,[131] the loading platform has been granted a waiver from State VOC RACT requirements based on the cost effectiveness of add-on controls. The conditions of the waiver limit VOC emissions from loading operations to less than 341 tons per year where the VOC vapor pressure of the liquid loaded exceeds 1.5 psia. Based on this emission limit as well as the terminal's location, it is assumed to primarily serve a local market, and would have significantly lower throughput than BWTX's proposed facility.

The Riverhead, NY terminal does not have similar emission points to the proposed BWTX facility. The volume and concentration of emissions streams are different based on the significantly lower throughput. EPA and NYDEC have separately concluded that installation of add-on controls at this facility would not be cost-effective, so no information is available on performance of controls at the Riverhead facility. Notwithstanding, BWTX believes that controls would be more costly and less effective if applied at BWTX's facility. First, the difference in the emission points means that the Riverhead Terminal could locate a control device on a platform adjacent to the loading berth, eliminating the need for subsea vapor pipelines. Second, throughputs are significantly different, and

[131] New York Department of Environmental Conservation. Permit ID 1-4730-000023/00030. Issued to United Riverhead Terminal, Inc.

may differ by a factor of 50–100 based on the relative potential VOC emission rates. Finally, the nearer distance to the shore (the Riverhead platform is located 1.3 miles from shore) would make use of an onshore control device potentially feasible, while this is not an option for BWTX's facility.

Based on the above considerations, the Riverhead, NY terminal is not a similar source.

Chevron El Segundo Terminal

The Chevron El Segundo terminal includes several multi-buoy moorings 1.4–1.5 miles from shore. The mooring buoys are used for unloading oil and loading refined products, and are associated with a nearby refinery. As discussed in the case-by-case permit application, the facility conducts controlled loading operations of refined products. According to two SCAQMD permits issued to Chevron USA Inc., controlled loading operations involve Handymax-sized (340,000 Bbl) Jones Act tankers possessing onboard control devices (carbon adsorption-based), loading rates are limited to 15,000 Bbl/hr, and liquids loaded are limited to petroleum products with vapor pressures of 0.75 psia or less. As discussed elsewhere in this application, Chevron evaluated a control system based on the use of subsea vapor recovery pipelines and submitted the analysis to EPA in 1994, asserting that the system would not be cost-effective. No such system was ever constructed.

The transfer operations completed at the Chevron El Segundo terminal take place on two tankers operated by Chevron affiliates. Based on the throughput levels reported in the application and the estimated round-trip voyage time between Offshore Galveston and Ningbo, PRC (a representative export destination), BWTX believes that a total 60 VLCCs (loading and underway to/from export destination) would be required to sustain operations at the proposed terminal. Purchase of a VLCC would cost approximately $93 million per unit based on current market rates, and the cost of retrofitting the vessel with control equipment would increase the capital cost to approximately $100 million. Operating expenses of approximately $14,000/day would be required for crews, stores, spare equipment, insurance, maintenance, and shipyard costs, corresponding to a cost of $570 MM/yr on an annualized basis.[132]

The emission points at the El Segundo terminal differ because the loaded vessels do not weathervane (multi-buoy moorings hold a vessel in a fixed position). The volume of the VOC emissions stream is approximately 1/80th that of BWTX's proposed facility, and is not similar. Finally,

[132] Capital recovery factor based on depreciation over 20 years at 7% interest per annum.

the overall purpose of the terminal (to distribute refined products along the Pacific Coast) permits the use of dedicated vessels having onboard controls. The actual control technique employed at the El Segundo terminal cannot be applied to BWTX's facility based on the volume of the emission stream and the business purpose of the facility.

Based on the above considerations, the Chevron El Segundo Terminal is not a similar source.

Phillips 66 Rodeo, CA Terminal

The Phillips 66 Rodeo, CA Terminal conducts loading and unloading operations at a dock connected to shore by a causeway. The loading berths appear to be less than 0.5 miles from shore based on satellite photography. Vapor recovery piping and an associated control device (thermal oxidizer) are located onshore. The facility's Title V permit indicates that it is exempt from MACT Y control requirements because it is a minor source.[133] Controls are required under BAAQMD Rule 8-44, however. The terminal is associated with a refinery, and is presumably used for loading and unloading of crude oil and refined products. Its throughputs appear to be lower than BWTX's proposed facility, as the permit limits it to 51,182 Bbl/day of crude oil receipts, and 59 tankers per year conducting unloading operations. BWTX's facility, by contrast, may load up to approximately 2 MMBbl of crude oil in a 24-hour period.

The emission points are not similar to BWTX's proposed facility because tanker vessels are moored at a berth connected to shore by a causeway. The volume and concentration of emissions are not similar due to differences in throughput. The cost and effectiveness of add-on controls is not comparable. Causeway-type terminals such as the Rodeo terminal use vapor recovery piping that runs along the dock to the onshore vapor processing system, and have access to onshore utilities. They only differ from onshore facilities lacking a causeway in terms of the length of the associated piping runs. The BWTX facility would have to employ subsea vapor recovery pipelines, construct an offshore platform to house a control device, and would not have access to utilities other than those delivered by supply vessels.

The distinction between causeway-, jetty-, and platform-type loading facilities; and terminals where loading takes place via mooring buoys is a fundamental one: the former contain fixed structures attached to the sea floor via pilings which can accommodate a control device and capture system

[133] BAAQMD Permit for Facility #A0016. Revised December 27, 2018.

when factored into the initial design. Control costs are significantly lower and have a high and established effectiveness. EPA has previously included in the MACT Y rulemaking docket an analysis comparing the cost of controls at the Richmond Long Wharf (causeway-type) to a hypothetical project for installing controls at the El Segundo marine terminal (multi-buoy type), and concluded that the costs for the offshore location were approximately doubled on a $/ton HAP basis.[134] EPA's analysis was used to justify subcategorization during the MACT Y rulemaking, and BWTX believes that it continues to provide support for concluding that causeway-type terminals are not similar to true offshore terminals located in open water locations.

Sources employing dockside controls, such as the Rodeo terminal, are not reasonably considered similar sources.

Chevron Richmond, CA "Long Wharf"

The Richmond "Long Wharf" facility is a causeway-type terminal located near a refinery in the San Francisco Bay Area. It is similar to the Rodeo terminal for purposes of the "similar source" analysis. Satellite photography indicates that it has a loading berth more than 0.5 miles from shore. The site's Title V permit lists applicable requirements from MACT Y and does not contain a permit shield for MACT Y.[135] The facility is also subject to BAAQMD Rule 8-44, and uses a vapor recovery unit as a control device for marine loading operations at the wharf. The loading berths have a combined throughput limit of approximately 147 MMBbl/yr, which is approximately half of the throughput proposed for BWTX's facility.

The emission points are not similar to BWTX's proposed facility because tanker vessels are moored at a berth connected to shore by a causeway. While the volume and concentration of emissions may be similar for some loading operations, the cost and effectiveness of add-on controls is not comparable. Causeway-type terminals such as the Richmond Long Wharf use vapor recovery piping that runs along the dock to the onshore vapor processing system, and have access to onshore utilities. They only differ from onshore facilities lacking a causeway in terms of the length of the associated piping runs. The BWTX facility would have to employ subsea vapor recovery pipelines,

[134] Mike Steinbrecher (Chevron Corporation) to David Markwordt (EPA OAQPS). March 13, 1995. *Proposed Rule: Marine Tank Vessel Loading Operations*. Docket item A-90-44-IV-D-136.

[135] BAAQMD Permit for Facility #A0010. Revised February 28, 2018.

construct an offshore platform to house a control device, and would not have access to utilities other than those delivered by supply vessels.

Based on the above considerations, the Richmond Long Wharf is not a similar source.

6.3 HAP Reductions achieved at similar sources

Of the sources considered, the only source that qualifies as a "similar source" is the Louisiana Offshore Oil Port (LOOP). The facility has functioned since 1981 as an unloading port. BWTX has not identified any requirements for control of air emissions from loading operations at LOOP, and presumes that the facility operates without add-on controls for air emissions. The facility's Deepwater Port license was last amended in 2000,[136] and BWTX cannot find any indication LOOP became subject to additional licensing requirements applied under MARAD's 2015 policy for licensing export-specific deepwater ports.[137] As noted previously, LOOP began operations as a crude oil export facility in February 2018.

LOOP, and tankers calling at LOOP, are subject to the submerged fill and VOC management plan design standards and work practices under applicable USCG and IMO regulations. These form the basis of the MACT requirements recommended in Section 8 of the application, and are considered to reflect the minimum level of control required to obtain a NOMA authorization.

EPA has identified the reduction efficiency of submerged fill for marine vessel loading operations as 60%.[138] BWTX believes that EPA's estimate is based on the ratio of saturation factors applicable to submerged loading of trucks and splash loading of trucks: $1 - 0.6/1.45 \approx 60\%$.[139] Therefore, the control alternatives considered in the following section must be capable of achieving a HAP emissions reduction of 60% or greater, where submerged fill is considered to be the reference control technique.

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136 65 Fed. Reg. 37814. June 16, 2000. Since Deepwater Port License Amendments are noticed in the *Federal Register*, BWTX performed a full-text search of a commercial library of *Federal Register* notices to arrive at its conclusion that LOOP's license has not been subsequently amended.

137 80 Fed. Reg. 26321. May 7, 2015.

138 75 Fed. Reg. 65115. October 21, 2010.

139 AP-42 Chapter 5, table 5.2-1.

Section 7
Alternatives Analysis

7.1 Introduction

A NOMA application must recommend an emission limitation that achieves the maximum degree of HAP reduction based on "available information," and must include supporting documentation that identifies alternative control technologies considered.[140] This section summarizes control alternatives considered to meet MACT requirements and summarizes the available information considered. This section also includes various additional information and analysis pertaining to particular alternatives that has been previously requested by EPA Region 6.

7.1.1 Organization

This section is divided into three parts. First, all control alternatives considered are listed, along with relevant supporting information. This portion constitutes the majority of the section. Second, relevant proposed emission standards are discussed, since they fall under the definition of "available information" (none were identified). Finally, the selected control technology is identified. A total of nine alternatives were considered to meet the minimum emission reduction requirement (Table 7-1).

Table 7-1 Summary of Alternatives Considered

Alternative	Selected?
Combined Work Practice	Yes
Vapor Recovery Unit	No
Vapor Combustor	No
Flare	No
Reverse lightering in lieu of constructing the project	No
Onshore vapor combustor	No
Controls onboard oil tanker	No
Recovery system onboard workboat	No
FSO with vapor return in lieu of constructing the project	No

[140] 40 CFR § 63.43(d)(2), (e)(2)(xii).

7.1.2 Project Selection

MACT for a new source refers to a level of control achievable by "the constructed or reconstructed major source."[141] Because similar phrasing employing a definite determiner appears in the definition of BACT as used in the PSD program,[142] BWTX supposes that the concept of "redefining the source" is equally applicable to case-by-case MACT determinations. In short, the elements of a facility's design which are inherent to its end, object, aim or purpose (which have been set for reasons independent of air permits) should normally not be altered as the result of a control technology review.[143] Because certain of the alternatives considered would involve abandoning inherent elements of the project's purpose, BWTX includes pertinent information here about the project's business purpose.

The overall purpose of the project is to safely export crude oil via deep draft tankers in a manner consistent with established operations and with a minimal impact to the marine environment, and includes the following design elements:

- Provide a safe and environmentally sustainable solution for the export of domestic crude oil supplies from major shale basins.
- Fully and directly load 384,000,000 barrels per year of crude oil for export.
- Fully and directly load Very Large Crude Carriers (VLCC) at the proposed facility via two (2) single point mooring (SPM) buoy systems.
- Minimize risks to worker safety and marine casualty hazards by placing logistic support facilities onshore to the extent practicable.
- Leverage the company's operational know-how and past experience designing, installing, and safely operating SPM-based terminals.

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[141] 40 CFR § 63.41 s.v. "Maximum achievable control technology (MACT) emission limitation for new sources."

[142] CAA § 169(3), referring to a level of control achievable "for such facility."

[143] Cf. *In Re Desert Rock Energy Company, LLC*. 14 E.A.D. 484, 530. September 24, 2009. Internal citations omitted.

- Minimize disruptions to the marine environment due to intensive dredging or installation of permanent structures on the ocean floor.

In developing its project, BWTX conducted a design alternatives analysis which is documented in the Deepwater Port License application.[144] BWTX considered design alternative involving the use of a new fixed platform, a refurbished fixed platform, as well as a "no project" alternative. The proposed project was found to be superior under several decision criteria unrelated to air permitting. A copy of pertinent portions are included in Appendix A of this application. Additional detail on design criteria motivating BWTX's rejection of a fixed platform in the vicinity of the SPM buoys is also given in Table 7-4 (below).

Finally, BWTX notes that EPA has recently articulated the presence of a platform structure as a fundamental design difference in determining which broad "source category" a project falls into for purposes of Section 112 of the Clean Air Act, consistent with treatment of such a feature as part of a project's basic design.[145] BWTX's project was fully conceived prior to the issuance of EPA's guidance, and could not have been altered for the sake of perceived differences in air permitting requirements.

7.2 Control Alternatives Considered

7.2.1 Combined Work Practice

The "combined work practice" (described in more detail in Section 8), includes three elements: restriction to ships adhering to bottom fill design, restriction to ships adhering to MARPOL Annex VI requirements to maintain a VOC management plan, and adherence to an operations manual consistent with USCG requirements.

Restricting use of the terminal to ships employing bottom fill has no marginal cost, as the standard (46 CFR § 153.282) is generally adhered to in shipbuilding. Use of bottom fill rather than splash loading would not increase the amount of head required of the onshore cargo transfer pumps, so

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[144] Deepwater Port License Application. Vol. 2, Sec. 2, pp. 2-47 – 2-52.

[145] Rob Lawrence (EPA R6) to Curtis Borland (USCG). Marine Vessel Loading emissions. April 5, 2019. Included as Appendix 4-d.

energy impacts are negligible. Although crude oil is not especially susceptible to static electricity hazards, bottom fill minimizes the formation of static charges (and thus the likelihood of a fire) and would have a positive secondary environmental impact.

Restricting use of the terminal to ships complying with MARPOL Annex VI has no marginal cost since compliance is required under EPA regulations implementing the Act to Prevent Pollution from Ships (33 USC §§ 1905–1915).[146] Proper operation of an inert gas generation system, as required under the terms of a VOC management plan, would reduce energy costs for the vessel operator, and would therefore reduce combustion emissions from onboard generators.

Development of an operations manual is associated with an initial cost on the order of $100,000, and complying with the manual involves annual labor and other operational costs on the order of $37,500,000. These expenditures are necessary to ensure compliance with USCG regulations. Adherence to the operations manual reduces the risk of casualty (oil spills, fire, etc.) and therefore has a positive secondary environmental impact. Energy impacts are negligible.

As noted above, EPA has identified the reduction efficiency of the submerged fill work practice as 60%,[147] which is equal to the minimum level of emissions reduction identified in the previous section. BWTX judges the combined work practice to be a cost-effective means of reducing HAP emissions, and has acceptable non-air quality environmental impacts and energy requirements.

7.2.2 Vapor Recovery Unit

Vapor recovery technologies are non-destructive systems which recover the hydrocarbon liquids present in loading vapor streams. Three forms of vapor recovery in use in organic liquid transfer operations are adsorption, refrigeration, and vapor balancing. Each is briefly described below.

[146] 75 Fed. Reg. 22896 Apr. 30, 2010.

[147] 75 Fed. Reg. 65115. Oct. 21, 2010.

Adsorption

Adsorption units operate by physical adsorption on a high surface area medium with an affinity for the pollutant of interest, such as activated carbon or zeolite. Although adsorption systems are often a preferred technology for relatively dilute emissions streams (e.g., 400–2000 ppm),[148] they have been installed at recently constructed/expanded onshore marine terminals in Texas. An adsorption system involves passing a gaseous pollutant stream over a bed of adsorbent. VOC constituents, including organic HAP, are adsorbed on the solid medium and the treated gas is then emitted to the atmosphere.

Adsorption systems must be regularly regenerated to maintain their performance. Adsorption is exothermic, and systems must be designed to maintain the bed within specified temperature ranges to ensure operation along the desired isotherm. Loss of temperature control can lead to lower emission reduction performance as well as fire and explosion hazards. A typical process for loading terminals ("vacuum adsorption") is to apply a vacuum to the adsorbent bed, altering the isotherm and forcing the hydrocarbons to desorb. The concentrated hydrocarbon stream released by the vacuum is condensed and recovered. Non-regenerative systems, in contrast, periodically replace the adsorbent bed, sending contaminated media to an offsite facility for treatment.

Typical equipment required for an adsorption system would be dual adsorbent beds, a vacuum pump and associated isolation valves for regeneration of the system, and a scrubber and storage tank for condensing and storing recovered VOC liquids. Adsorption systems typically achieve 90–99% control of captured vapors, depending on the choice of adsorbent and the frequency of regeneration.

Refrigeration

Refrigeration units, or refrigerated condensers, reduce the temperature of a gaseous emission stream below its dew point, converting some or all of the VOC vapors into their liquid phase and enabling recovery and reduction of emissions. Refrigeration units are most adaptable to rich

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[148] EPA OAQPS. *Technical Bulletin: Choosing an Adsorption System for VOC: Carbon, Zeolite, or Polymers?* Publication EPA 456/F-99-004. May 1999.

emission streams with a minimal air flow.[149] As noted elsewhere in this application, refrigeration technology has been the basis of several onboard control systems in use by shuttle tankers operating in the North Sea. In Norway, the Norwegian Pollution Control Authority requires the installation of VOC emissions reduction units on most shuttle tankers serving the Norwegian continental shelf.[150] Vapors from ship cargo tanks are compressed, dried, and condensed using a closed loop refrigeration system, and condensed VOC (termed "LVOC") is stored in an onboard fuel tank for use by the vessel's auxiliary or propulsion engines.[151] Such systems are reported to achieve VOC reduction rates of 78–100%, and the HAP reduction potential is assumed to be similar.

Vapor Balancing

Vapor Balancing systems collect loading vapors displaced during loading operations and route these to a storage tank associated with the loading operation.[152] Such a system was previously used in shuttle tanker loading operations associated with an FPSO in federal waters offshore of California, as is noted in the National Research Council report contained in the MACT Y docket,[153] Vapor balancing is not a standard practice due to the widespread use of floating roof storage tanks. However, the technique has been deployed at the Valdez Marine terminal,[154] which is subject to a 98% HAP emissions reduction requirement (40 CFR § 63.562(d)(2)).

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[149] EPA OAQPS. *Technical Bulletin: Refrigerated Condensers for Control of Organic Air Emissions*. Publication EPA 456/R-01-004. December 2001.

[150] U.S. Securities and Exchange Commission (SEC). Form 20-F for Teekay Offshore Partners L.P. Year ending December 31, 2018.

[151] *Wärtsilä Hamworthy VOC Recovery System* (Product Brochure). 2015. Accessed December 17, 2019, at https://cdn.wartsila.com/docs/default-source/product-files/ogi/recovery/brochure-o-ogi-recovery-voc-system.pdf.

[152] 40 CFR § 63.561, s.v. "Vapor Balancing System."

[153] Docket Item II-I-4.

[154] "Alyeska Pipeline starts up tanker vapor-control system at Valdez terminal." *Oil & Gas Journal*. May 11th, 1998.

Consideration of Vapor Recovery Control Systems

None of the vapor recovery technologies identified are technically feasible when considered in light of BWTX's planned project.

The foremost consideration is space limitations on the CALM buoy: Adsorption-based systems require space to house adsorption beds, vacuum pumps, monitoring instruments, and recovered liquid storage tanks. Refrigeration-based systems require space to house refrigerant compressors, heat exchangers, gas cleaning systems, and recovered liquid storage tanks. Vapor balance systems require the presence of a fixed roof storage tank operating at lower pressure than the vapor return line. Vapor recovery equipment requires access to utilities (electricity or fired engines) to power equipment with moving parts, such as compressors and vacuum pumps. Finally, vapor recovery equipment requires periodic maintenance, and arrangements must be made to remove the recovered VOC liquids. The CALM buoy lacks space to house the equipment (including fired engines), lacks access to electricity, and will be unmanned.

Refrigeration-based vapor recovery systems have been successfully deployed as onboard control devices on shuttle tankers. BWTX's project is for export of crude oil and is not associated with any offshore oil production. It will therefore not use shuttle tankers. It will instead load cargoes onto unaffiliated crude carriers chartered by customers. It is not feasible in the context of the project's business model to restrict use of the terminal to tankers using onboard recovery systems such as are employed by shuttle tankers operating in the Norwegian continental shelf.

Similar to a vapor combustor-based system, a vapor recovery system would be subject to USCG regulations applying to Marine Vapor Control Systems. These include requirements to eliminate potential overpressure and vacuum hazards and eliminate ignition hazards by placing detonation arrestors and inerting/enriching systems at appropriate places. The system would require approval by a certifying entity. Although the USCG rules permit placement of vapor recovery unit within 30 meters of a mooring (33 CFR § 154.2109), in contrast to vapor combustors, the space limitations noted above prevent this, and it is not possible to place a vapor recovery system on an offshore structure adjacent to the CALM buoy due to the presence of a weathervaning tanker.

The only possible measure to overcome these technical challenges would be to construct a manned offshore platform outside of the ATBA. As explained elsewhere, however, construction of a platform currently serves no purposes in the context of BWTX's planned project, presents unacceptable safety risks, and presents its own technical feasibility issues (backpressure/condensate formation in vapor recovery pipeline, access to utilities for enriching the vapor stream, etc.) which lack demonstrated solutions.

7.2.3 Vapor Combustor

Vapor combustors are capable of controlling emissions streams which are relatively rich and which have relatively stable flow rates. Such devices can achieve emissions reductions from 95–99.9% of the captured vapors. Due to space limitations on the CALM buoy, use of a vapor combustor would entail construction of an offshore platform. Several factors have motivated BWTX's rejection of this alternative.

Table 7-2 Platform-based vapor combustor as control alternative.

Consideration	Comment
Ability to meet an emission limitation	Undemonstrated, innovative technology with technical feasibility issues when applied to the BWTX project. No proven design for modifying SPM buoy to accommodate vapor recovery. No proven design for vapor recovery/processing system for loading vapors on an offshore platform. Interruptions to operations based on the use of unproven technology have been estimated based on a BWTX affiliate's experience with vapor combustion units employing a new and emerging design (Serial No. 2).
Cost	High and unpredictable cost for uncertain emissions reduction when applied to BWTX's project. Costs are **$ 484,387 per ton HAP reduced.**
Non-air quality health impacts.	Manned platform storing and receiving flammable gases not otherwise needed for BWTX's project. Unacceptable risk to worker safety. High safety risk for transportation and handling of fuel gas (LPG) and other utilities. High safety risk for personnel transportation and offshore operations.

Consideration	Comment
Non-air quality environmental impacts	Disturbances to marine environment, associated with construction of a platform not otherwise required for BWTX's project. Risk of accidental spills associated with handling wastewater and fuel not otherwise required for BWTX's project.
Energy requirements	Unacceptable costs for fuel gas (LPG) and liquefied nitrogen to operate the vapor control system. As designed, BWTX's project does not require deliveries of fuel to offshore locations.

Ability to meet an emission limitation

BWTX does not believe that such a system, if applied to its SPM facility, would actually achieve such a reduction on a continuous basis due to technical challenges:

Innovative Technology. Such a system has not been demonstrated in practice and is not commercially available. Such a system would constitute innovative control technology. This factor would exacerbate the issues noted below, and creates the risk of as yet unidentified technical challenges.

Distance. Because BWTX's offshore loading facility is of the single-point mooring type (cf. Table 3-2, above), a significant distance would separate the SPM facility from the platform. Unlike other types of offshore terminals, the loaded vessel is not moored in a fixed position. As noted in BWTX's October 25, 2019, submission, the platform and control device would have to be located at least 1350 meters from the closest CALM buoy. For other types of offshore loading facilities employing fixed berths, the vapor combustor could be located as near as 30 meters to the loading berth (33 CFR § 154.2109(c)(1)).[155] The distance contributes to other challenges noted below.

[155] EPA's analysis in promulgating MACT Y refers to the need to "…locate control equipment *adjacent* to the offshore terminal…" (60 Fed. Reg. 48393. Sep. 19, 1995, emphasis supplied), based on an analysis provided by the owner of a platform-type terminal in Riverhead, NY (Docket item A-90-44 IV-D-30).

Permitting difficulties. Such a system would create permitting difficulties. These include the need to obtain approval from a USCG-approved certifying entity and the need to obtain regulatory exemption for USCG requirements relating to placement of detonation arresters and enriching/dilution systems. The required certification (from an approved agency such as ABS of Lloyd's Registry) for a modified SPM design involving vapor recovery would add time to the construction period.

Operability issues. Operating subsea lines to carry loading vapors to a platform and control device installed 1350 meters or more from BWTX's CALM buoys would create operability issues. Two serious and related operability issues are the formation of liquid condensate in the vapor recovery pipeline and backpressure created at the vessel. A third operability issue is corrosion in the vapor recovery pipeline.

Crude oil loading vapors include inert gas contained in a ship's cargo hold, which contains a substantial portion of water vapors. Since the vapor recovery pipeline would traverse temperature gradients as it travels to the seabed and back, vapors would condense in the vapor pipeline, and condensate would have to be removed by pigging. Since both the pig launcher and pig catcher would be located on the platform, dual pipelines would be required for round trip pigging. If the vapor line was 10% full of liquid, and the SPM was a half mile from the platform, the liquid slug from pigging this line would be on the order of 650 cubic feet (5000 gallons). A large sump (about 8' diameter by 20' tall) would be needed to catch the slug (to keep it from going into the vapor blower), and the oily wastewater would have to be regularly pumped up to a tank located on the platform for regular off-take via barge. This would result in substantial water and waste impacts that are not otherwise required for BWTX's project.

The loading vapors coming from a ship are at low pressure (usually less than 2 psig). Ship cargo tanks operate within narrow pressure ranges, outside of which loading operations must be immediately halted. Thus, relatively minor increases in frictional losses in the vapor recovery pipeline (caused by the presence of condensate) would impair operations. Pigging the pipeline as necessary to manage back pressure could be required one or more times during each individual loading operation. The loading operation would have to be suspended since the pig is a potential ignition source. The suspension of loading operations would prevent the facility from operating continuously as intended. Disruption of loading operations would interfere with BWTX's contractual commitments to load within a fixed time period, as vessels engaged must depart on schedule to meet other committed ports of call. In addition, the loading disruption would result in longer vessel idling times and higher rates of vessel emissions than are otherwise required for BWTX's project.

Corrosion would interfere with operability as well. The vapors coming off of a ship would routinely have some level of H_2S, some oxygen, and some water vapor. The presence of these three constituents means that corrosion issues will occur. At BWTX's affiliates, filters and detonation arrestors on marine vapor lines have plugged up due to corrosion products from just a short run (less than 100 feet) of vapor piping. Round-trip pipelines running over 1350 m along the seabed will be susceptible to corrosion, and options for removing the products of corrosion and performing maintenance on the pipeline will be limited because the pipelines will lie approximately 89 feet below water on the ocean floor.

***Cost*[156]**

The system would not achieve cost-effective reductions of HAP emissions. The cost of emissions reduction has been developed following guidance in the *EPA OAQPS Air Pollution Control Cost Manual* ("APCCM"), where applicable. Because APCCM is not intended for use with innovative technologies,[157] BWTX has made appropriate adjustments to the prescribed methodology for

[156] The Agency's regulations for case-by-case MACT determinations specify that an applicant is to provide cost analysis for its selected control technology. Specifically, an applicant is to provide:

> Supporting documentation including identification of alternative control technologies considered by the applicant to meet the emission limitation, **and analysis of cost and non-air quality health environmental impacts or energy requirements for the selected control technology**;

40 CFR § 63.43(e)(2)(xii) (emphasis added). BWTX consequently provides the following cost information not because it believes the applicable regulations call for it, but only at the request of the agency.

[157] "*Finally, new and emerging technologies are not generally within the scope of this Manual. The control devices included in this Manual are generally well established devices with a long track record of performance*." APCCM, Chap. 1 at 1-3.

estimating contingency and operating costs of control equipment.[158] These adjustments include an increased contingency factor over that recommended by APCCM as well as quantification of the cost impacts associated with the risk of implementing an innovative control technology.

The cost analysis is presented in Table 7-3 (below). If not otherwise indicated, the basis for each line item is BWTX's own engineering and economic analysis for an innovative, unproven technology that has not been implemented anywhere in the United States.

[158] To the extent costs are to be considered under the applicable regulations, the guidance contained in the associated *Federal Register* preamble clarifies that costs are considered in the context of determining whether an existing source constitutes a "similar source," and that "[t]he uninstalled costs of controls should not be a factor in determining similarity across emission units. What should be a factor is the uninstalled cost of controls *plus* the costs associated with installation and operation of those controls. Therefore, whenever costs are quantified, such costs should include the purchase price of controls plus the costs associated with installation and operation of those controls for the source in question." 61 Fed. Reg. 68384, 68395 (Dec. 27, 1996) (emphasis in original). BWTX has implemented EPA's guidance in the analysis that follows.

Table 7-3 HAP Cost Effectiveness Analysis for Innovative and Unproven Vapor Combustor on Platform

Item	Description	Basis	Estimation Factor	Item Cost
Capital Costs				
Direct Costs				
1	VCU and Associated Equipment			$37,142,400.00
2	Instrumentation	APCCM Chap. 3.2, Sec. 2, Tbl. 2.8 (henceforth "Tbl 2.8")	10%	$3,714,240.00
3	Sales Tax		6.25%	$2,321,400.00
4	Freight		6%	$2,228,544.00
5	Total Purchased Equipment Cost (PEC)	Sum of Items 1--4		$45,406,584.00
6	Foundations (structure reinforcement)	Tbl 2.8	8% of PEC	$3,632,526.72
7	Handling and Erection	Tbl 2.8	14% of PEC	$6,356,921.76
8	Electrical	Tbl 2.8	4% of PEC	$1,816,263.36
9	Piping	Tbl 2.8	2% of PEC	$1,180,571.18
10	Instrumentation	Tbl 2.8	1% of PEC	$454,065.84
11	Painting	Tbl 2.8	1% of PEC	$454,065.84
12	Direct Installation Costs	Sum of Items 6--11		$13,894,414.70
13	Platform	Platform buy & build		$191,000,000.00
14	Vapor Handling	Floating & subsea hoses, buoy & PLEM mods for vapor		$22,000,000.00
15	Total Direct Costs (TDC)	Sum of Items 5,12--14		$272,300,998.70
Indirect Costs				
17	Engineering		12.25% of TDC	$33,356,872.34

Item	Description	Basis	Estimation Factor	Item Cost
18	Construction and Field Expenses		8% of TDC	$21,784,079.90
19	Contractor fees (profit)	Tbl. 2.8	10% of TDC	$27,230,099.87
20	Start-up	Tbl. 2.8	2% of TDC	$5,446,019.97
21	Performance Test	Tbl. 2.8	1% of TDC	$2,723,009.99
22	Contingencies		40% of TDC	$108,920,399.48
23	Total Indirect Costs	Sum of Items 17--23		$199,460,481.55
24	Escalation	3 year delay in startup		$17,951,443.34
25	Total Capital Investment (TCI)	Sum of Items 15,23		$489,712,923.59
Annual Costs				
Direct Costs				
28	Raw Materials			
29	Utilities	Fuel gas (VCU), diesel (generators), water (potable, etc.)		$164,660,851
30	Maintenance	Service, consumables, testing, maint contracts, etc.	10% of TDC	$27,230,100
31	Subtotal (Lines 28–30)			$191,890,951
32	Opex Related to Platform & Vapor Recovery System	Salaries, Helicopter, Support Vessels, lease for additional submerged land, etc.		$28,403,350
33	Risk 1: Demurrage Due to Technology			$5,950,714
34	Risk 1: Lost Profit Opportunity Due to Technology			$105,377,220
35	Total Direct Annual Costs			$331,622,234
Indirect Costs				
36	Property Taxes	No state taxation per OCSLA § 1333	0%	

Item	Description	Basis	Estimation Factor	Item Cost
37	Insurance and Administrative Charges	3% of TCI (APCCM sec. 2.5.5.8).	3% of TCI	$14,691,388
38	Capital Recovery	CRF based on i=0.0425 and n=20 yrs (APCCM Chap. 2, "Incinerators and Oxidizers, Nov. 2017 ed.)	7.52% of TCI	$36,836,125
39	Total Indirect Annual Costs			$51,527,513
Recovery Credits				
40	Materials	No materials recovered.		$0.00
41	Energy	No additional energy recovery.		$0.00
Totals				
42	Total Annualized Costs	Item 35 + Item 39		$383,149,747
Cost Effectiveness				
43	HAP Emission Rate (Work Practice Alternative)			833 tpy
44	HAP Emission Rate (Platform+VCU Alternative)	95% reduction		42 tpy
45	HAP Emissions Reduction			791 tpy
46	Cost Effectiveness (HAP)	Item 42 / Item 45		**$484,387 per ton**

Non-air quality health impacts

Since a platform is not otherwise dictated by the design for BWTX's facility, it would pose unacceptable risks to the health and safety of persons manning the platform.

Safety is BWTX's number one core value. All project design considerations need to include an evaluation of the safety risks created as part of the operational philosophy. The offshore platform would entail operations that create an inherent risk to personnel safety: transportation of personnel via helicopter, storage of highly flammable and hazardous fuels, and exposure of personnel to harsh offshore weather conditions. The presence of ignition sources (vapor combustion units) in proximity to sources of propane leaks would create the risk of a fire. Rupture of a propane container could result in a fireball or boiling liquid expanding vapor explosion (BLEVE).

The vapor recovery pipelines would require nitrogen to facilitate pigging operations, jet fuel for the helicopter, diesel for the generators, pumps, cranes, etc., and such utilities would have to be delivered in isocontainers via barge, and not received by pipeline. The delivery of utilities via barge increases the vessel traffic to the DWP. Propane storage in particular which would be heavily utilized, with cranes used to lifted containers of compressed, liquefied propane on and off the platform. Crane operations on a platform, especially those that involve a supply boat, are hazardous operations with risks that cannot be fully mitigated.

At onshore operations conducted by BWTX's affiliates, the safety skid is typically located within 100 ft of the ship vapor connection.[159] The safety skid includes equipment that analyzes the loading vapors as they arrive from the ship and injects appropriate quantities of fuel gas (typically natural gas) to ensure that the vapor is out of its explosive range. Since the platform- located VCU would have to be located at least 1350 m from the SPM buoy,[160] considerations other than safety would dictate the location of the safety skid. The blower for the VCU is the most significant ignition source (metal to metal contact), and a spark in a non-inerted vapor stream has the potential of causing a flashback all the way to the ship.

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[159] The safety skid is installed pursuant to USCG requirements at 33 CFR § 154.2107.

[160] 33 CFR § 150.910.

Another safety concern is the operation of helicopters near VCU stacks. Given space limitations, the VCU stacks would exhaust in close proximity to a helideck. If the wind were blowing directly from the VCU stack to the helideck, the helicopter would be in danger of losing power while in flight, because the exhaust gas from the VCU will be low in oxygen and high in temperature.

Consistent with its commitment to safe operations, BWTX has sought to minimize to the extent possible the number of personnel required to be present in harsh offshore conditions. With the current two SPM buoy design, two mooring masters must be present at all times on each VLCC calling at the facility to ensure that all preloading safety checks are conducted, to ensure safe unloading operations and to maintain communications with the onshore facility. The mooring masters will work in shifts and will be lodged onshore. With an offshore platform, BWTX would have to increase the number of personnel and lodge personnel on an offshore platform, creating unwarranted safety risks.

In conclusion, non-air quality health impacts (in the form of safety risks) for this control system are unacceptable.

Non-air quality environmental impacts

Non-air quality environmental impacts associated with installation of an offshore platform that is otherwise not needed for BWTX's project are summarized in Table 7-4, below.

Based on the information detailed below, constructing additional subsea pipelines, an offshore platform, and vapor combustors would also pose unacceptable non-air quality environmental impacts.

Table 7-4 Health, Safety, and Environmental Impacts for Offshore Platform

Health, Safety, or Environmental Impact	Bluewater SPM Project	Addition of Platform with Control Device to Bluewater SPM Project
Minimizes the potential for interference with natural processes	✓ Bluewater SPM project design allows for moored vessels to accommodate for existing natural processes	X Fixed platform design consists of rigid fixed structures incapable of accommodating for various offshore processes once installed.

Health, Safety, or Environmental Impact	Bluewater SPM Project	Addition of Platform with Control Device to Bluewater SPM Project
Minimizes Personnel Occupancy Required	✓ Un-manned system (excluding the assist tugs during berthing and de-berthing)	X Requires personnel to be onsite the fixed platform during operations, exposing them to inherent hazards of operation. Potential risk of transportation of personnel to and from offshore. Potential risk to personnel accident due to highly hazardous environment on the platform from storage of diesel and propane. Incidents such as vapor cloud release, vapor cloud from oil spills, collision from vessels, etc. risks now exist.
Minimizes exposure of workforce to secure facilities in preparation of a severe storm event	✓ Un-manned system which can be remotely secured in preparation of severe storm event	X Requires personnel to be onsite to prepare fixed platform for severe storm event
Length of Construction Schedule	✓ 1-month timeframe of disturbance to the marine environment	X Longer timeframe of disturbance to the marine environment
Maintenance Requirements	✓ Shorter timeframe of required maintenance..	X Longer timeframe of required maintenance
Minimizes potential for overwater spills	✓ Project design limits required maintenance and no fuel refilling operations.	X Project design requires increased maintenance and multiple facilities requiring fuel thereby resulting in an increased potential for overwater spills. Offtake of oily wastewater generated by pigging operations creates additional risk for overwater spills.
Minimizes Above Water Footprint	✓ Smaller footprint above the water.	X Larger footprint above the water especially for locations in proximity to shipping lanes.
Minimizes Seabed Water Footprint	✓ Smaller seabed footprint .	X Larger seabed footprint therefore larger eco disturbances during construction.
Minimizes damage to vessel due to Accidental Collision	✓ SPM chains allow for impact absorption and would cause less damage to vessel.	X Traffic of support vessels around platform creates increased risk of collisions.
Accidental Collision Damage to Personnel	✓ Proposed project does not include a manned fixed structure.	X High safety concerns with vessel collision with an occupied fixed platform, consisting of multiple

Health, Safety, or Environmental Impact	Bluewater SPM Project	Addition of Platform with Control Device to Bluewater SPM Project
		pressurized vapor lines and fuel storage.
Minimizes operational noise impacts	✓ Proposed project design limits the required noise generating structures and noise impacts.	X Project design including platform requires multiple diesel generators and facilities resulting in increased ambient noise impacts.
Minimizes operational lighting impacts	✓ Proposed project SPM design minimizes required above water surface infrastructure requiring lighting.	X Proposed fixed platform design requires multiple light fixtures for operations.
Minimizes operational impacts to water quality	✓ Proposed project SPM design does not include any water uptake/discharges.	X Proposed fixed platform design requires multiple water uptake/discharges thereby resulting in water quality impacts.
Minimizes TSS and benthic impacts for construction activities	✓ Proposed project design minimizes the required installation of infrastructure resulting in decreased TSS and benthic habitat impacts.	X Proposed project design requires installation of increased infrastructure resulting in increased total suspended solids (TSS) and benthic habitat impacts.
Minimizes operational impacts to plankton	✓ Proposed project SPM design does include any water uptake/discharges thereby avoiding impacts to plankton within the water column.	X Proposed fixed platform design requires multiple water uptake/discharges thereby resulting in uptake of plankton.
Minimizes construction and operational impacts to fisheries	✓ Proposed project design minimizes water column and seabed impacts.	X Additional platform and subsea pipelines require installation of numerous large diameter piles and multiple subsea lines.

Energy Requirements

As indicated in Table 7-3 (above), the cost of fuel gas for enriching the loading vapors created at BWTX's facility to the extent required by USCG regulations is estimated at $ 164MM per year. At onshore facilities, enriching gas is typically sourced from pipeline-borne natural gas. The offshore platform would require regular deliveries of liquefied propane in isocontainers, making fuel gas costs significantly higher for the same volume of crude oil loaded. The vapor recovery pipelines would require nitrogen to facilitate pigging operations, and such nitrogen would have to be delivered via barge in isocontainers, rather than received by pipelines.

Energy requirements for this control system would be unacceptable.

7.2.4 Flare

Flare stacks are primarily used as safety devices to control large, intermittent releases of flammable gases.[161] They are commonly used in oil production operations, including offshore operations. Flare systems require knockout drums to prevent liquid carryover, fuel gas to ensure a constant pilot flame and positive flow through the stack, and an elevated structure with sufficient setback to ensure that thermal radiation does not endanger personnel. In the case of assisted flares, additional equipment is used to supply steam or air to promote smokeless operation.

Figure 7-1 is a photograph of an offshore Floating Production Unit (FPU) in the North Sea which features a flare. The flare is used to dispose of high-pressure gas that is generated during oil production operations. The figure also shows a Suezmax-range shuttle tanker, the *Stena Alexita*, receiving produced oil via tandem loading. Though it has since been scrapped, the shuttle tanker was time chartered to the oil company operating the production site, and used an onboard refrigeration system to control loading emissions (i.e., the flare on the FPU was not used for this purpose).[162]

[161] EPA OAQPS. *Air Pollution Control Technology Fact Sheet: Flare*. Publication EPA-452/F-03-019. n.d.
[162] SEC. Form 20-F for Teekay Offshore Partners L.P. Year ending December 31, 2006.

Figure 7-1 Use of a flare on offshore floating production unit

Although elevated flares are commonly used for offshore oil production, they are not typically adapted to loading operations. At onshore facilities, elevated flares are not typically used as the primary control device for loading operations. At petroleum refineries, however, existing flare systems may be suitable to handle some loading operations, especially those involving pressurized loading or unloading of compressed hydrocarbon liquids.

Consideration of Flare

The use of a flare to control loading operations at BWTX's facility is not technically feasible. As noted above, vapor destruction units cannot be located within 30 meters of a loading mooring under USCG regulations, and in any case the CALM buoy could not accommodate a flare stack. The flare stack would have to be located on a manned, offshore platform. A flare would present the same technical feasibility issues as a vapor combustor (detailed in a previous submission), including unacceptable safety hazards and issues relating to the management of condensate formation and backpressure in the vapor recovery pipeline. A flare would also present additional risks for helicopter operations due to the height of its stack and the oxygen-deficient plume it generates, and would require additional fuel gas (beyond that required by a vapor combustor) to ensure positive flow through the stack at all times. In sum, the use of a flare in place of a vapor combustor would not mitigate the safety, engineering, and other technical challenges associated with the use of a vapor combustor.

7.2.5 Reverse lightering in lieu of constructing the project

Reverse lightering is not a control technology. Instead, it represents a strategy for exporting large volumes of crude oil without actually constructing any new source subject to DPA and CAA Title I requirements. Two scenarios were considered for the export of a volume of crude oil equivalent to the maximum throughput rate of the proposed SPM project. Information about reverse lightering has been supplied to EPA on August 15, 2019, October 23, 2019, and November 15, 2019. Although reverse lightering operations are not a control technology for purposes of the Case-by-case MACT evaluation, BWTX selected its project after considering the environmental impacts of its project as well as impacts associated with other crude oil export methods involving reverse lightering.

Scenarios Considered

A total of three scenarios are considered: the project scenario and two lightering scenarios:

Table 7-5 Scenarios Considereed

Scenario	Description
Project Scenario	Export of 384 MMBbl/yr of crude oil onto VLCC's via SPM buoys.
Lightering Scenario 1	Export of 384 MMBbl/yr of crude oil onto VLCC's via reverse lightering.
Lightering Scenario 2	Export of 384 MMBbl/yr of crude oil onto VLCC's with a partial load onshore, and remaining load via reverse lightering.

The project scenario is the SPM facility described elsewhere in this application. Lightering Scenario 1 involves the use of Aframax lightering vessels to fill VLCC's via ship-to-ship transfers. Lightering Scenario 2 involves the partial loading of VLCC's at onshore facilities with the remainder of the load completed via ship-to-ship transfers using an Aframax lightering vessel. It is assumed that this scenario would require additional dredging in the vicinity of the Port of Corpus Christi to accommodate VLCC traffic.

For purposes of this analysis, the nominal capacity of an Aframax tanker is 500 MBbl and the nominal capacity of a VLCC is 2,000 MBbl (cf. Table 3-1, above). A partially loaded VLCC receives a partial load of 1,000 MBbl onshore and the remainder of its load via reverse lightering.

The following categories of impacts are assessed. Air emissions are quantified, while impacts to nearshore aquatic environments and impacts to port facility congestion are identified qualitatively.

- Air Emissions: Uncontrolled loading emissions, controlled loading emissions, and vessel engine emissions.
- Impacts to nearshore aquatic environments: Impacts associated with dredging and excavation activities.
- Casualty Risks: Impacts associated with the increased risk of casualty due to congestion and ship-to-ship transfer operations.
- Business Impacts: Anticipated time to complete full loading of a VLCC.

Air Environmental Impacts: Loading and Vessel Engine Emission

Air Emission Rates from stationary and mobile sources for the three scenarios are summarized below.

Table 7-6 Comparison of Emission Rates

Pollutant	Project Scenario	Lightering Scenario 1	Lightering Scenario 2
NO_X	1120	6037	4915
CO	307	1452	1183
SO_2	45	214	174
Particulate	39	184	150
VOC	14495	14927	7665
GHG (as CO_2e)	63809	331582	275498
HAP	637	652	333
H_2S	2	2	1

While VOC and HAP emissions are highest for the project scenario and for lightering scenario 1, due primarily to emissions from uncontrolled loading operations, emissions of products of combustion (NO_X, CO, SO_2, Particulate, GHG) are highest for the two lightering scenarios. H_2S emissions are not significant under any of the scenarios. BWTX has conducted dispersion modeling and photochemical modeling for stationary source emissions associated with its projects, finding no adverse impacts.

Non-air Environmental Impacts: Nearshore Aquatic Environments

Of the three scenarios considered, the project scenario and lightering scenario 1 involve relatively minor disruptions to nearshore aquatic environments, while lightering scenario 2 involves more significant impacts. BWTX has considered minimizing impacts to the local aquatic environment as an important priority in selecting its project.

Lightering Analysis (Summary)
Bluewater Texas Terminal LLC

Total Emissions by Scenario (tpy)			
Pollutant	Project Scenario	Lightering Scenario 1	Lightering Scenario 2
NO_X	1120	6146	4969
CO	307	1490	1202
SO_2	45	220	177
Particulate	39	189	152
VOC	14495	14932	7667
GHG	63809	339497	279455
HAP	637	652	333
H_2S	2	2	1

Total Emissions by Component Activity (tpy)

Activity	Pollutant	Project Scenario	Lightering Scenario 1	Lightering Scenario 2
Vessel Engines	NO_X	1120	6117	4941
Vessel Engines	CO	307	1469	1181
Vessel Engines	SO_2	45	216	174
Vessel Engines	Particulate	39	187	150
Vessel Engines	VOC	39	188	151
Vessel Engines	GHG	63809	305836	245794
Vessel Engines	HAP	1	3	2
Loading Emissions (uncontrolled)	VOC	14456	14601	7373
Loading Emissions (uncontrolled)	HAP	636	642	324
Loading Emissions (uncontrolled)	H_2S	2	2	1
Loading Emissions (controlled)	VOC	0	143	143
Loading Emissions (controlled)	HAP	0	6	6
Loading Emissions (controlled)	SO_2	0	4	4
Loading Emissions (controlled)	NO_X	0	29	29
Loading Emissions (controlled)	CO	0	21	21
Loading Emissions (controlled)	Particulate	0	2	2
Loading Emissions (controlled)	GHG	0	33660	33660

Supporting Calculations (Vessel Emissions for Lightering Scenario 1)
Bluewater Texas Terminal LLC

Vessel Engine Emission Factors

Pollutant	Emission Factor (lb/hp-hr)
NOx (VLCC and Aframax)	0.0237
NOx (Tug & LSV)	0.0158
CO	0.0055
SO_2	0.0008
$PM/PM_{10}/PM_{2.5}$	0.0007
VOC	0.0007
CO2e	1.1450
HAP	0.000011

Maximum Engine Loads

Vessel Type	Maximum Load (kW)	Maximum Load (hp)
VLCC	26000	34866
Aframax	13000	17433
Tractor Tug		10000
Lightering Support Vessel (LSV)	1119	1500

Operating Levels

Lightered Load (MBbl)	Total Throughput (MBbl/yr)
500	384000

Vessel Activities Per Lightered Load

Vessel Type	Operating Mode	Number of Vessels	Engine Load	Duration (hr)
Aframax	In transit (loaded)	1	90%	12
Aframax	In transit (unloaded)	1	60%	12
Aframax	Lightering	1	90%	12
Aframax	Docked (loading)	1	10%	12
VLCC	Lightering	1	25%	12
Tractor Tug	Mooring assist	2	100%	3
LSV	Lightering Support	1	100%	12

Maximum Emission Rates (lb/event)

Pollutant	Onshore Aframax engines	Onshore assist tugs	Transit	Lightering	LSVs
NO_X	495	789	7428	6933	284
CO	115	275	1726	1611	99
SO_2	17	40	254	237	15
$PM/PM_{10}/PM_{2.5}$	15	35	220	205	13
VOC	15	35	221	206	13
CO2e	23953	57250	359294	335341	20610
HAP	0.2	0.6	3.5	3.2	0.2

Emission Factors (lb/MBbl)

Pollutant	Onshore tanker engines	Onshore assist tugs	Transit	Lightering	LSVs
NO_X	0.99	1.58	14.86	13.87	0.57
CO	0.23	0.55	3.45	3.22	0.20
SO_2	0.03	0.08	0.51	0.47	0.03
$PM/PM_{10}/PM_{2.5}$	0.03	0.07	0.44	0.41	0.03
VOC	0.03	0.07	0.44	0.41	0.03
CO2e	47.91	114.50	718.59	670.68	41.22
HAP	0.0005	0.0011	0.007	0.006	0.0004

Emission Rates (tpy for equivalent volume exported)

Pollutant	Onshore tanker engines	Onshore assist tugs	Transit	Lightering	LSVs	Grand Total
NO_X	190	303	2852	2662	109	6117
CO	44	106	663	619	38	1469
SO_2	6	16	97	91	6	216
$PM/PM_{10}/PM_{2.5}$	6	13	84	79	5	187
VOC	6	14	85	79	5	188
CO2e	9198	21984	137969	128771	7914	305836
HAP	0.1	0.2	1.3	1.2	0.1	3

Notes:

1.VOC, NOx, PM, CO and SO_2 emissions are based on AP 42 section 3.4 emission factors. SO2 emission factor adjusted to account for 1000 ppmw sulfur concentration.
2. NOx emission factors for marine diesel engines based on MARPOL Annex VI emission limit.
3. Operating load and activity duration estimates explained in Sec. 13.
4. HAP emissions are the sum of AP-42 section 3.4 emission factors for Formaldehyde, Acrolein, Acetaldehyde, BTX, and total PAHs.
5. Brake-specific fuel consumption (BSFC) of marine diesel assumed to be 7000 Btu/hp-hr (AP-42 Sec. 3.3).
6. GHG emission factors per 40 CFR Part 98, Subpart C, Tables C-1 and C-2 (Distillate Fuel Oil No. 2).

Supporting Calculations (Vessel Emissions for Lightering Scenario 2)
Bluewater Texas Terminal LLC

Vessel Engine Emission Factors

Pollutant	Emission Factor (lb/hp-hr)
NOx (VLCC and Aframax)	0.0237
NOx (Tug and LSV)	0.0158
CO	0.0055
SO_2	0.0008
$PM/PM_{10}/PM_{2.5}$	0.0007
VOC	0.0007
CO2e	1.1450
HAP	0.000011

Maximum Engine Loads

Vessel Type	Maximum Load (kW)	Maximum Load (hp)
VLCC	26000	34866
Aframax	13000	17433
Tractor Tug		10000
Lightering Support Vessel (LSV)	1119	1500

Operating Levels

Lightered Load (MBbl)	Total Throughput (MBbl/yr)	Partial Load (MBbl)
500	384000	1000

Vessel Activities Per Lightered Load

Vessel Type	Operating Mode	Number of Vessels	Engine Load	Duration (hr)
Aframax	In transit (loaded)	1	90%	12
Aframax	In transit (unloaded)	1	60%	12
Aframax	Lightering	1	90%	12
Aframax	Docked (loading)	1	10%	12
VLCC	Lightering	1	25%	12
VLCC	Docked (loading)	1	10%	48
VLCC	In transit (loaded)	1	90%	12
VLCC	In transit (unloaded)	1	60%	12
Tractor Tug	Mooring assist	2	100%	3
LSV	Lightering Support	1	100%	12

Maximum Emission Rates (Partial load portion, lb/event)

Pollutant	Onshore tanker engines	Onshore assist tugs	Transit	Lightering	LSVs
NO_x	3962	789	14857	0	0
CO	920	275	3452	0	0
SO_2	135	40	508	0	0
$PM/PM_{10}/PM_{2.5}$	117	35	439	0	0
VOC	118	35	442	0	0
CO2e	191624	57250	718588	0	0
HAP	2	1	7	0	0

Emission Factors (Partial load portion, lb/MBbl)

Pollutant	Onshore tanker engines	Onshore assist tugs	Transit	Lightering	LSVs
NO_x	3.96	0.79	14.86	0	0
CO	0.92	0.28	3.45	0	0
SO_2	0.14	0.04	0.51	0	0
$PM/PM_{10}/PM_{2.5}$	0.12	0.04	0.44	0	0
VOC	0.12	0.04	0.44	0	0
CO2e	191.62	57.25	718.59	0	0
HAP	0.0018	0.0006	0.0069	0	0

Maximum Emission Rates (Lightering portion, lb/event)

Pollutant	Onshore tanker engines	Onshore assist tugs	Transit	Lightering	LSVs
NO_x	495	789	7428	6933	284
CO	115	275	1726	1611	99
SO_2	17	40	254	237	15
$PM/PM_{10}/PM_{2.5}$	15	35	220	205	13
VOC	15	35	221	206	13
CO2e	23953	57250	359294	335341	20610
HAP	0.2	0.6	3.5	3.2	0.2

Emission Factors (Lightering portion, lb/MBbl)

Pollutant	Onshore tanker engines	Onshore assist tugs	Transit	Lightering	LSVs
NO_x	0.99	1.58	14.86	13.87	0.57
CO	0.23	0.55	3.45	3.22	0.20
SO_2	0.03	0.08	0.51	0.47	0.03
$PM/PM_{10}/PM_{2.5}$	0.03	0.07	0.44	0.41	0.03
VOC	0.03	0.07	0.44	0.41	0.03
CO2e	47.91	114.50	718.59	670.68	41.22
HAP	0.0005	0.0011	0.007	0.006	0.00

Emission Rates (tpy for equivalent volume exported)

Pollutant	Onshore tanker engines	Onshore assist tugs	Transit	Lightering	LSVs	Grand Total
NO_x	475	227	2852	1331	55	4941
CO	110	79	663	309	19	1181
SO_2	16	12	97	45	3	174
$PM/PM_{10}/PM_{2.5}$	14	10	84	39	2	150
VOC	14	10	85	40	2	151
CO2e	22995	16488	137969	64386	3957	245794
HAP	0.2	0.2	1	1	0.04	2.4

Notes:

1.VOC, NOx, PM, CO and SO_2 emissions are based on AP 42 section 3.4 emission factors. SO2 emission factor adjusted to account for 1000 ppmw sulfur concentration.
2. NOx emission factors for marine diesel engines based on MARPOL Annex VI emission limit.
3. Operating load and activity duration estimates explained in Sec. 13.
4. HAP emissions are the sum of AP-42 section 3.4 emission factors for Formaldehyde, Acrolein, Acetaldehyde, BTX, and total PAHs.
5. Brake-specific fuel consumption (BSFC) of marine diesel assumed to be 7000 Btu/hp-hr (AP-42 Sec. 3.3).
6. GHG emission factors per 40 CFR Part 98, Subpart C, Tables C-1 and C-2 (Distillate Fuel Oil No. 2).

Supporting Calculations (Vessel Emissions for Project Scenario)
Bluewater Texas Terminal LLC

Equipment source	Number of Vessels	Pollutant	Power (hp)	Power (kw)	Speed (rpm)	Load Factor (%)	Annual Operation (hr)	Emissions Factor		Emissions per vessel	
								Value	Units	lb/hr	tpy
Work boat	2	NOx	1,500	1,119	750	25.00%	8,760	0.0158	lb/hp-hr	5.92	25.92
		CO						0.0055	lb/hp-hr	2.06	9.03
		SO_2						0.001	lb/hp-hr	0.30	1.33
		$PM/PM_{10}/PM_{2.5}$						0.0007	lb/hp-hr	0.26	1.15
		VOC						0.0007	lb/hp-hr	0.26	1.16
		CO2e						1.1450	lb/hp-hr	429.38	1880.66
		HAP						0.000011	lb/hp-hr	0.004	0.02
Tug boat	2	NOx	10,000	7,457	750	25.00%	8,760	0.0158	lb/hp-hr	39.45	172.78
		CO						0.0055	lb/hp-hr	13.75	60.23
		SO_2						0.001	lb/hp-hr	2.02	8.86
		$PM/PM_{10}/PM_{2.5}$						0.0007	lb/hp-hr	1.75	7.67
		VOC						0.0007	lb/hp-hr	1.76	7.72
		CO2e						1.1450	lb/hp-hr	2862.50	12537.75
		HAP						0.000011	lb/hp-hr	0.03	0.12
VLCC propulsion engine	2	NOx	34,866.57	26,000	100	10.00%	8,760	0.0237	lb/hp-hr	82.54	361.52
		CO						0.0055	lb/hp-hr	19.18	83.99
		SO_2						0.001	lb/hp-hr	2.82	12.35
		$PM/PM_{10}/PM_{2.5}$						0.0007	lb/hp-hr	2.44	10.69
		VOC						0.0007	lb/hp-hr	2.46	10.77
		CO2e						1.1450	lb/hp-hr	3992.22	17485.94
		HAP						0.000011	lb/hp-hr	0.04	0.17

Pollutant	Total Emissions (tpy)
NO_X (VLCC)	723
NO_X (Tug and Workboat)	397
CO	307
SO_2	45
Particulate	39
VOC	39
GHG	63809
HAP	0.6

Notes:
1.VOC, NOx, PM, CO and SO_2 emissions are based on AP 42 section 3.4 emission factors. SO2 emission factor adjusted to account for 1000 ppmw sulfur concentration.
2. NOx emission factors for marine diesel engines based on MARPOL Annex VI emission limit.
3. GHG emission factors per 40 CFR Part 98, Subpart C, Tables C-1 and C-2 (Distillate Fuel Oil No. 2). Brake-specific fuel consumption of 7000 Btu/hp-hr assumed.

Supporting Calculations (Controlled and Uncontrolled Loading Emissions)
Bluewater Texas Terminal LLC

Constants

Quantity	Units	Value
Vapor Phase MW (hourly)	lb/lbmol	60.3
Vapor Phase MW (annual)	lb/lbmol	59.4
Ambient Temp. (hourly)	°F	95
Ambient Temp. (annual)	°F	72.1
Product:		Crude Oil
VP (hourly)	psia	9.32
VP (annual)	psia	6.44
Annual Throughput	MBbl/yr	384000
Pumping Rate (SPM Loading)	MBbl/hr	80
Pumping Rate (Lightering)	MBbl/hr	40
H_2S Max Vapor Concentration	ppmw	130
HAP Max Vapor Concentration	wt. %	4.4%
Control Device Destruction Efficiency	%	99%
Capture System Efficiency	%	99%
Vapor Heat Content	Btu/lb	20000
Saturation Factor		0.2
Loading Loss Factor (hourly)	lb/MBbl	106.0
Loading Loss Factor (annual)	lb/MBbl	75.3

Emission Factors

Activity	Pollutant	Hourly EF (lb/MBbl)	Annual EF (lb/MBbl)
Uncontrolled Loading	VOC	106.0	75.3
Uncontrolled Loading	HAP	4.7	3.3
Uncontrolled Loading	H_2S	0.014	0.010
Dockside Loading (Uncaptured Emissions)	VOC	1.060	0.753
Dockside Loading (Uncaptured Emissions)	HAP	0.047	0.033
Dockside Loading (Uncaptured Emissions)	H_2S	0.00014	0.00010
Dockside Loading (Controlled)	VOC	1.050	0.745
Dockside Loading (Controlled)	HAP	0.046	0.033
Dockside Loading (Controlled)	SO_2	0.026	0.018

Activity	Pollutant	EF (lb/MMBtu)	Units
Dockside Loading (Controlled)	NO_X	0.1	lb/MMBtu
Dockside Loading (Controlled)	CO	0.074	lb/MMBtu
Dockside Loading (Controlled)	Particulate	0.0075	lb/MMBtu
Dockside Loading (Controlled)	GHG	117.6	lb/MMBtu

Activity	Pollutant	Emission Rate (lb/hr)	Emission Rate (tpy)
SPM Loading (Uncontrolled)	VOC	8483.71	14455.96
SPM Loading (Uncontrolled)	HAP	373.28	636.06
SPM Loading (Uncontrolled)	H_2S	1.10	1.88
Lightering (Uncontrolled)	VOC	4241.86	14455.96
Lightering (Uncontrolled)	HAP	186.64	636.06
Lightering (Uncontrolled)	H_2S	0.55	1.88
Dockside Loading (Uncaptured Emissions)	VOC	42.42	144.56
Dockside Loading (Uncaptured Emissions)	HAP	1.87	6.36
Dockside Loading (Uncaptured Emissions)	H_2S	0.01	0.02
Dockside Loading (Controlled)	VOC	41.99	143.11
Dockside Loading (Controlled)	HAP	1.85	6.30
Dockside Loading (Controlled)	SO_2	1.04	3.54
Dockside Loading (Controlled)	NO_X	8.40	28.62
Dockside Loading (Controlled)	CO	6.22	21.18
Dockside Loading (Controlled)	Particulate	0.63	2.15
Dockside Loading (Controlled)	GHG	9877.1	33660

Notes:

1. NO_X and VOC Emission Factors Explained in Sec. 13
2. H_2S Emission Factor Explained in Appendix Z (PSD Application)
3. SO_2 Emission Factor Based on Complete Combustion of H_2S in Waste Stream
4. Particulate and GHG Emission Factors from AP-42 Sec. 1.4
5. CO Emission Factor Based on 100 ppmv (3% O_2 reference), based on typical TCEQ BACT requirements.
6. VOC emission factor based on hydrocarbon vapor pressure from speciation analysis

Scenario	Port Congestion	Ship-to-ship Transfers
		require ship-to-ship transfers.
Lightering Scenario 1	Increased lightering vessel (Aframax-size range) traffic within the Port of Corpus Christi.	Increased ship-to-ship transfers in offshore lightering areas which take longer and have greater commercial impact.
Lightering Scenario 2	Increased VLCC and lightering vessel (Aframax-size range) traffic within the Port of Corpus Christi and increased support vessels required within port area.	Increased ship-to-ship transfers in offshore lightering areas which take longer and have greater commercial impact.

Business Impacts: Time to Complete Export Operation

An indicator of the overall efficiency of each scenario is the total time required to complete full loading of a VLCC.

Table 7-9 Summary of Time Requirements for Different Scenarios

Row	Parameter	Value	Comment
1	Time to complete reverse lightering operation	12 hr	Based on analysis of AIS data (15-Aug submission).
2	Time to complete SPM loading operation	25 hr	Based on maximum loading rate of 80 MBbl/hr.
3	Time to complete onshore loading of Aframax	12 hr	Based on loading rate of 40 MBbl/hr.
4	Time to complete partial onshore loading of VLCC	72 hr	Based on analysis of AIS data (15-Nov submission).
5	Transit time to/from offshore lightering area (each leg of voyage)	12 hr	Based on analysis of AIS data (15-Aug submission). The distance from Galveston
6	**Total time for loading 1 VLCC (Project Scenario)**	25 hr	Row 2
7	**Total time for loading 1 VLCC (Lightering Scenario 1)**	192 hr	(2000/500) × (Row 1 + Row 3 + 2×Row 5)
8	**Total time for loading 1 VLCC (Lightering Scenario 2)**	168 hr	(1000/500) × (Row 1 + Row 3 + 2×Row 5) + Row 4

Of the three scenarios, the total time to accomplish a loading operation is the lowest in the project scenario.

The distance that an Aframax lightering vessel covers in traveling between an offshore lightering area and a shoreside terminal facility varies depending on where the lightering operation takes place and where the shoreside terminal is located. For example, the distance from Galveston Offshore

Lightering Area (GOLA) to the Port of Texas City is approximately 60 statute miles, while the distance from the Port of Corpus Christi to an associated offshore lightering area is approximately 80 statute miles. As indicated above (Row 5), actual transit times determined from AIS data have been used to estimate Aframax fuel consumption.

Emission calculations for the three scenarios are given in the following pages as Figure 7-2.

Figure 7-2 Emission Calculations for Lightering Analysis

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7.2.6 Onshore vapor combustor

The use of subsea pipelines to route captured loading vapors to a shoreside control device is specifically mentioned in the MACT Y docket. In a July 21, 1993 letter to EPA, Chevron compared the cost of a recently-completed control project for its Richmond, CA "Long Wharf" to a hypothetical project for control of its El Segundo, CA terminal, based on the use of subsea lines.[163] BWTX has determined that such a control system was designed and installed at the Gaviota Interim Marine Terminal (GIMT), and operated for six months. BWTX believes that Chevron, as one of the companies interested in developing oil production from the Point Arguello field, had specific experience with the engineering challenges in developing the system at GIMT. Chevron's 1991–1995 correspondence with EPA and USCG, identifying engineering and regulatory challenges, and advocating for consideration of control systems not involving subsea lines,[164] is best understood in this context.

Although BWTX believes that the system at GIMT was the only vapor recovery pipeline-based control system actually constructed, the concept is also discussed in detail in a Development and Production Plan for the Santa Ynez Unit proposed by Exxon Corporation for a proposed marine terminal in California waters off the coast of Santa Barbara. The system was presented as a solution for controlling vapors generated during loading of tankers at a nearshore SPM (SALM-type), and is described as an "innovative technology".[165] As depicted in Exxon's plan, the vapor recovery line was to be tied to the suction side of an onshore compressor, and therefore to operate at a partial vacuum. Removal of liquid condensate from the vapor recovery line was to be removed by pigging, with a pig launcher and receiver to be located on the sea floor adjacent to the PLEM.[166] The system was never constructed, and tanker loading from Santa Ynez Unit production was done through the FPSO OS&T.

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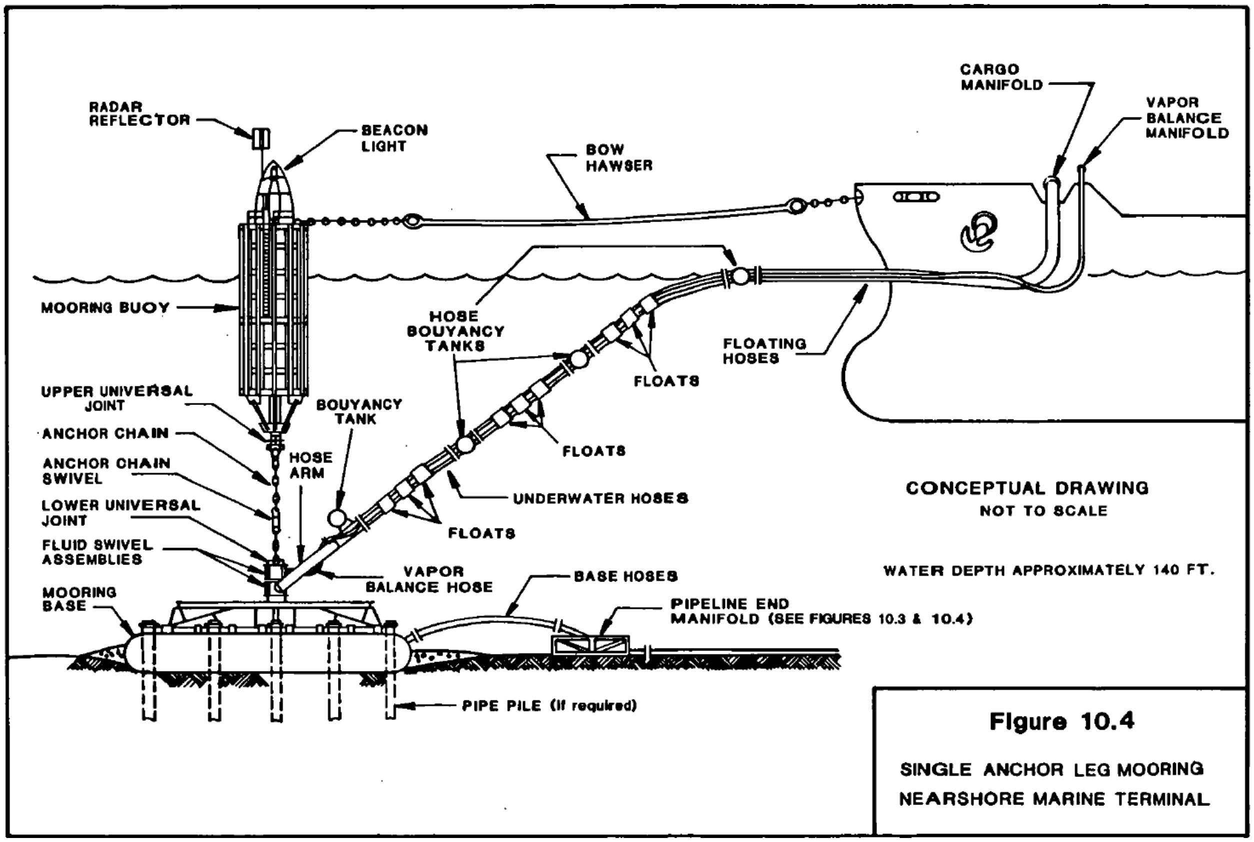
[163] A-90-44 IV-D-136.

[164] A-90-44 II-E-40, A-90-44 II-D-49, A-90-44 II-D-63, A-90-44 IV-D-136.

[165] *Memorandum of Agreement II. Development of Santa Ynez Unit, Santa Barbara Channel*. Between the State of California, California State Lands Commission, California Air Resources Board, County of Santa Barbara, Santa Barbara County Air Pollution Control District, and Exxon Company, USA. October 8, 1982.

[166] Interior Department. October 1982. Development and Production Plan: Santa Ynez Unit Development. Exxon Corporation. at X-7–X-12.

Figure 7-3 Conceptual Drawing for Vapor Recovery Pipeline with SPM loading[167]



The engineering challenges associated with subsea vapor recovery pipelines are best understood through reference to USCG regulations (33 CFR Part 154, Subpar P) requiring that facility vapor control systems eliminate sources of ignition to the maximum practicable extent, and eliminate potential overpressure and vacuum hazards.[168] While the placement of detonation arresters is one issue that would require a regulatory exemption, BWTX believes that the most serious challenge is designing a means for removing liquid condensate from the vapor collection system.[169] Liquid condensate would be expected in subsea vapor recovery pipelines, its formation being encouraged by temperature differences between the ship's cargo tank and the subsea pipeline, the presence of water vapors (especially in inert gas), and the length of the pipeline. If not regularly removed, liquid

[167] *Id*. at X-23.

[168] 33 CFR § 154.2100.

[169] 33 CFR § 154.2100(h).

condensates could cause excessive back-pressure in the vapor return pipeline, and they could flow as liquid slugs, posing a risk to the vapor recovery blowers.

Liquid condensate could be removed through pigging of the vapor recovery pipeline if the pipelines are installed in pairs (allowing for round-trip travel of the pig), and a pigging system of this type was installed in the GIMT vapor recovery system. However, the rate of condensate formation could be significant, and pigging could be required frequently, one or more times *during* a loading operation (transfer operations would have to be suspended), depending on the level of back pressure experienced at connection to the ship's cargo tank. The high volume of the liquid slug returning with the pig would necessitate a solution for catching and disposing of oily wastewater. BWTX expects that such a system would be prone to operational difficulties, and these difficulties would be prohibitive for a vapor recovery pipeline running 25 miles along the seabed.

BWTX does not believe that a subsea vapor recovery pipeline system has been adequately demonstrated at any facility, and should therefore be rejected as technically infeasible. The system at GIMT was not in operation for a sufficiently long time period to allow for full consideration of its operational reliability. In any case, the distance to shore (3500 feet) was significantly less than in the present case. In order to determine whether any other subsea vapor recovery pipeline systems have been actually installed and operated (besides GIMT), BWTX contacted manufacturers of SPM systems, each of whom has confirmed that they have not commissioned any SPM using a vapor recovery PLEM (correspondence attached in Appendix A).

Finally, BWTX has taken note of a presentation made by a John Zink Hamworthy Combustion ("John Zink") engineer[170] which apparently depicts the recovery of crude oil vapors from a SPM-type loading facility using a vapor recovery pipeline and PLEM. Recent correspondence with John Zink confirms that the technology has never been applied in practice (correspondence attached in Appendix A).

[170] Puglisi, Marco. 2012. Vapor Control on Crude Oil Loading. Accessed April 18, 2019 at https://www.platts.com/IM.Platts.Content/ProductsServices/ConferenceandEvents/2012/pc379/presentations/d2_4_Marco_Puglisi.pdf.

7.2.7 Controls onboard oil tanker

The use of a control device located onboard the loaded vessel was identified as an option for mooring buoy-type loading operations:[171]

> *The Coast Guard agrees that these types of facilities present some unique problems, and that having the vapor processing unit on board the vessel is a viable option*.

BWTX has identified three instances where this control technique has been used in a sustained fashion, suggesting that it has demonstrated operational reliability and performance, and that there are no prohibitive physical or operational constraints preventing its application.[172] As noted previously, the Ellwood Marine Terminal (EMT) conducted barge loading of crude oil in compliance with Santa Barbara APCD Rule 327 using dedicated barges with onboard vapor processing systems. As the following excerpt from the minutes of a 2009 meeting of the California State Lands Commission (concerning the necessity of using of double-hulled barges for transport of crude oil from EMT) indicates, the two controlled barges used during EMT's operating history (*Jovalan* and *Olympic Spirit*) were specially designed vessels, and no comparable vessels of the same type were used at the time.[173]

> *MR. GREIG: The difficulty that we have with the double-hulled barge isn't just the availability of the barge. It's the availability of the vapor recovery unit that goes on the barge. So, while there might be double hulled barges along the Pacific Coast that would work for service in our type of use, they would have to be retrofit and in that a vapor recovery unit that meets the requirements of Santa Barbara County Air Pollution Control District be installed on that barge. The only vapor recovery unit like that that's approved by the district is owned and patented by Public Service Marine, that owns the barge Jovalan, who actually owns the Olympic Spirit and who we contracted with, the developer to build a second or another double-hulled barge, again, with that vapor recovery, so that the time delay is a combination of the availability of the barge, the construction and installation of vapor recovery units and*

[171] 55 Fed. Reg. 25407. June 21, 1990.

[172] Onboard controls involving combustion-based controls alone have not been identified. These would be constrained by safety hazards and would be subject to approval by a USCG certifying entity (46 CFR § 39.1013(c)).

[173] California State Lands Commission. June 1, 2009. Meeting Minutes at 53–55.

then permitting and getting that confirmed through the APCD that's going to work in that service.

...

MR. SHEEHY: So they do have not a double-hulled barge with the necessary vapor recovery system? They don't have one that you can use?

MR. GREIG: Correct. There's one more barge—

MR. SHEEHY: Other than the Jovalan.

MR. GREIG: The Olympic Spirit has that vapor recovery unit, but it's contracted to Tesoro.

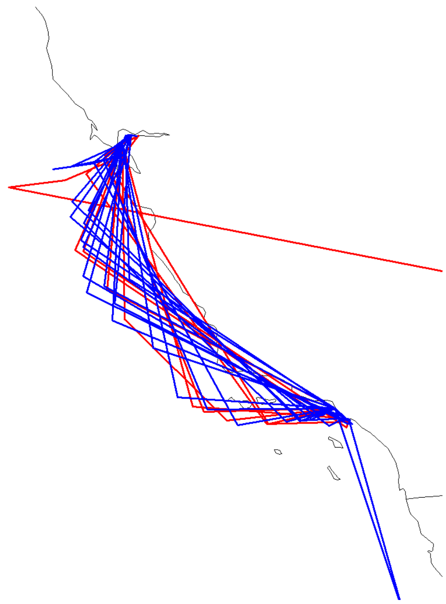
A second example of onboard vapor recovery technology is noted for Chevron's El Segundo marine terminal. The facility is subject to SCAQMD Rule 1142, which requires controls of loading and lightering activities in South Coast Waters. Two active SCAQMD Permits to Operate have been located for onboard control devices (carbon adsorption).[174]

The control devices are associated with two Handymax-sized (340,000 Bbl), Jones Act oil tankers, the *Mississippi Voyager* and the *Florida Voyager*. MARAD data lists the operator of both vessels as Chevron Shipping Co LLC.[175] Figure 7-4 shows two-month trajectories for the two vessels, indicating that their traffic is almost entirely confined to trips between Long Beach or El Segundo (likely loading areas), and either the Chevron Richmond Refinery "Long Wharf," mentioned above, or the Phillips 66 Rodeo Refinery (likely offloading areas). In this case, Chevron affiliates own the terminal in El Segundo and also operate the ships that are loaded at the terminal along relatively fixed itineraries.

[174] SCAQMD Permit to Operate G41614 (July 7, 2016), G28359 (November 13, 2013).

[175] Maritime Administration. United States Flag Privately-Owned Merchant Fleet Report. January 2019.

Figure 7-4 Trajectories for the Florida Voyager and the Mississippi Voyager



A final example of onboard vapor recovery is from shuttle tankers operating in the North Sea.[176] Oil Producers in the Norwegian North Sea are currently subject to a non-methane VOC emission limit of 0.45 kg/m^3 oil loaded (159 lb/MBbl) for transfer operations between an offshore production area such as an F(P)SO and a shuttle tanker. During their service as shuttle tankers,[177] the *Randgrid* and the *Navion Norvegia* employed onboard vapor recovery systems based on carbon adsorption. The control system is visible onboard the *Navion Norvegia*'s deck in one video published by a crew member in 2011.[178]

The installation of control devices onboard shuttle tankers is a reasonable measure for a fleet of vessels subject to a common jurisdiction. Shuttle tankers may be in the Aframax or Suezmax size-class, so scaling up of the technology for VLCC-sized vessels is likely feasible. Individual offshore production sites rely on dedicated fleets of shuttle tankers in cases where produced oil cannot be transported to market via pipeline. Figure 7-5, for example, shows voyage trajectories for the

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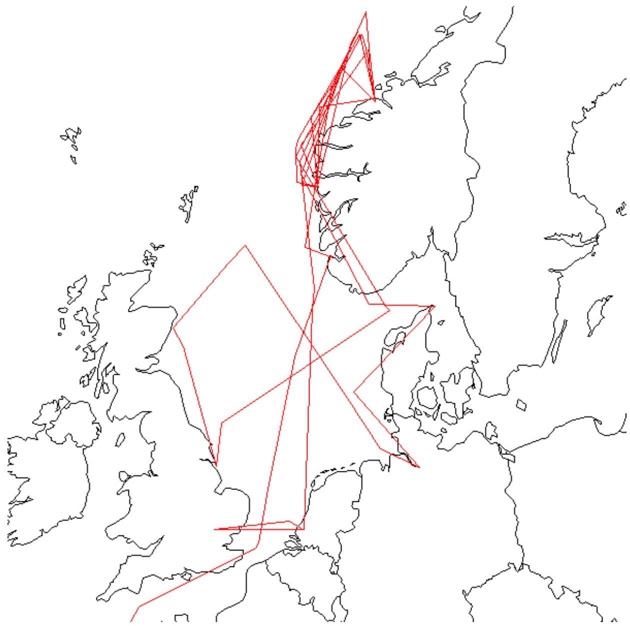
[176] "Developing an effective crude oil vapor recovery system." *Port Technology*. Accessed April 18, 2019 at https://www.porttechnology.org/industry_sectors/developing_an_effective_crude_oil_vapor_recovery_system.

[177] The *Randgrid* has been converted to an FSO and the *Navion Norvegia* to an FPSO.

[178] "Navion Norvegia." Posted by user MrIRA1973. July 26, 2011. Accessed April 18, 2019 at https://www.youtube.com/watch?v=tJvuNoVnZuc.

Randgrid between October 2014 and May 2015.[179] The tanker calls at ports in Norway, Denmark, Germany, Netherlands and UK, repeatedly returning to offshore areas where oil production units are known to operate.

Figure 7-5 Trajectory for the *Randgrid*



All observed examples of onboard control devices are in cases where an offloading point relies on a dedicated fleet of tankers to transport its product. In such a context, the vessels are controlled by the terminal owner, or specific vessels are contracted for use by the terminal owner. In other words, the use of a dedicated vessel fleet is part of the terminal's business model, and it is not unreasonable to impose specific equipment requirements on such a dedicated fleet. In the case of the proposed deepwater port, however, use of control devices onboard the loaded ship is not reasonable. VLCC's calling at the port are expected to be foreign-flagged vessels owned and operated by companies unaffiliated with BWTX. While equipment requirements applying to crude

[179] The May 2015 voyage was to a shipyard in Singapore, presumably for its eventual conversion to an FSO.

carriers may be a reasonable approach to regulating offshore loading and lightering operations, BWTX believes that such requirements cannot be reasonably imposed on a specific terminal.

7.2.8 Recovery system onboard workboat

A third possibility is the use of a control device mounted onboard a workboat. Such a control technique is mentioned in a June 25, 1992, presentation made by Chevron staff to EPA. The presentation describes a proposal by Public Service Marine, Inc. (PSMI), for a workboat having a 12,500 Bbl/hr vapor processing capacity.[180] As noted above, PSMI was the owner of the two barges (*Jovalan* and *Olympic Spirit*) used for controlled loading at EMT.

The workboat concept was presented to EPA as a possible strategy for Chevron's Estero Bay marine terminal to achieve compliance with what is currently codified as San Luis Obispo County APCD ("SLO APCD") Rule 427. While the rule was under consideration in 1991, it was not promulgated until 1995, and the compliance date was not until April 26, 1997. The terminal ceased operations no later than mid-1999 and no workboat was actually deployed at the Estero Bay terminal. For loading operations conducted between 1997 and 1999, compliance with Rule 427 was achieved through the use of emissions offsets.[181]

BWTX is aware of at least one workboat in actual use for the processing of vapors during marine loading operations.[182] Foss Maritime is the owner of the *San Pedro* (reported as calling at El Segundo), as well as three additional barges (*FDH 35-3, FDH 35-4,* and *FDH 35-5*) equipped with onboard carbon adsorption units. Foss Maritime holds operating permits issued by SCAQMD which restrict the loading rate of each barge to 8,000–12,000 Bbl/hr and restrict cargoes handled to petroleum liquids having a maximum vapor pressure of 0.75 psia at loading temperature.[183]

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[180] A-90-44 II-E-40.

[181] SLO APCD. July 3, 1997. Engineering Evaluation: Emission Banking and Permit to Operate. Permits 2147 etc. Chevron Products Company et al.

SLO APCD. April 30, 1998. Permit to Operate C-1232-A-1. Issued to Chevron Pipeline Company.

[182] Marcon International, Inc. December 2004. *Tank Barge Market Report*. Accessed April 18, 2019 at http://www.marcon.com/library/market_reports/2004/TB/TB1204.pdf. At 9.

[183] SCAQMD Permits to Operate R-G2640 (May 12, 2009), G25415 (June 28, 2013), G25416 (June 28, 2013), and G25421 (June 28, 2013).

The system is described as follows by a Foss Maritime employee:[184]

> *"The San Pedro barge is the only barge in the world that we know of that does third-party vapor processing," said Costin. "We had a customer come to us and since we already had our operating permits under the South Coast Air Quality Management District, it was an easy fit to convert the barge to be able to take what we call 'third-party vapors.' It's an ideal platform that we can work offshore because it's outfitted with special mooring and surge gear. As the ship is loading cargo from a terminal or other source, we're connected on the outboard side to their vapor line and they push their vapors down through our system. The barge can process up to 15,000 barrels an hour."*

BWTX believes that workboat-type technology could conceivably be applied to the offshore loading of crude oil, but believes that there are significant differences between the bunker loading operations controlled by the Foss Maritime barges and the proposed crude oil export terminal. The three factors are positioning of the workboat, environmental conditions offshore, and the necessary capacity of the recovery system. Since tankers at El Segundo are spread-moored (and therefore held in a fixed position), a workboat can be moored in close proximity to the loaded tanker. Mooring of a service vessel in proximity to a VLCC being loaded at an SPM would require modification of the safety zone and design of the support vessel with a dynamic positioning system to maintain a fixed position with respect to the VLCC. Environmental conditions would present a challenge for achieving continuous reduction of HAP emissions, since the service vessel would have to depart from its position in the event of strong currents or winds. Finally, the size of the vessel and onboard control equipment would have to be scaled up to accommodate a significantly higher volume of vapors: the higher vapor pressure, loading rate, and presence of inert gas in the loading vapors imply a vapor flow rate two orders of magnitude greater than would be expected for the Foss Maritime barges.

BWTX finds that the workboat concept is not unreasonable in principle, but should be treated as technically infeasible because no similar system has been demonstrated in practice.

[184] "Scrubbing VOCs from bunkers helps clean the air." March 23, 2011. *WorkBoat*. Accessed April 18, 2019 at https://www.workboat.com/archive/scrubbing-vocs-from-bunkers-helps-clean-the-air/.

7.2.9 Controls onboard FSO constructed in lieu of SPM buoy

Lavagna et al[185] describe a system for tandem offloading of Liquefied Natural Gas (LNG) from an LNG FPSO to an LNG carrier. While the focus of the presentation is on the design of the necessary cryogenic hose used to accomplish the transfer operation, the system includes the use of a cryogenic line for return of cold boil-off gas to the FPSO for flaring:

> *A three offloading lines configuration is required to achieve a LNG flow rate similar to a land based terminal and handle vapor back to the FLNG. The LNG transfer is carried out with two 18" inner diameter COOL™ hose sections allowing up to 10,000 m^3/h total flow rate. An identical 18" extra vapor return line is used to handle the cold Boil-Off Gas (BOG) resulting from the heat transferred to the LNG during cargo operations. The offloading line configuration is designed to accommodate severe environmental configurations.*[186]

As discussed above, BWTX has not identified any instance of a flare on an FPSO or FPU being used to control crude oil loading vapors. Notwithstanding, the report illustrates the possibility of a vapor return system that would not be subject to the same liquid condensate formation issues as a subsea vapor return pipeline. The tandem loading configuration is illustrated in Figure 7-6 for an FSO moored offshore of Angola, offloading to a shuttle tanker. As discussed previously, BWTX believes that it is not unreasonable to equip a tanker with a control device if it is under the control of the terminal operator. Additionally, since FSO's and FPSO's are frequently built by converting existing Aframax or Suezmax tankers, they would be appropriately sized for controlling vapor flows of the magnitude that could be expected during an 85,000 Bbl/hr crude oil transfer operation.

BWTX has additionally determined that the FPSO "OS&T," which formerly operated in federal waters off the coast of Santa Barbara (cf. discussion above) conducted controlled offloading operations via tandem loading onto the Handymax-size shuttle tanker *Exxon Jamestown*, which was specially equipped for vapor balance operations.[187]

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[185] Lavagna, Damien, Le Touzé, Laurent, and Fournier, Jean Robert. 2011. "LNG Tandem Offloading — A Qualified Technology Now Ready for FLNG Projects." Presentation from the Offshore Technology Conference held in Rio de Janeiro, Brazil, 4–6 October 2011.

[186] Id. at 3.

[187] Interior Department. October 1982. Development and Production Plan: Santa Ynez Unit Development. Exxon Corporation. At VIII-59, IX-11.

Two photographs depicting tandem loading operations are depicted in Figure 7-6. Shown are an external turret-moored FSO moored offshore of Angola as well as the *Overseas Tampa* receiving cargo from *FPSO Turritella* in the Gulf of Mexico. As discussed previously, BWTX believes that it is not unreasonable to equip a tanker with a control device if it is under the control of the terminal operator. Additionally, since FSO's and FPSO's are frequently built by converting existing Aframax or Suezmax tankers, they would be appropriately sized for controlling vapor flows of the magnitude that could be expected during an 85,000 Bbl/hr crude oil transfer operation.

Interior Department. September 20, 1985. Approval re: Santa Ynez Unit Development and Production Plan.
Brennan, JR. "Screw pumps move heavy California offshore crude effectively. *Oil & Gas Journal* 92:60–62.

Figure 7-6 Tandem Offloading from F(P)SO to Shuttle Tanker[188,189]

Thus, existing technology from related fields could conceivably be combined to arrive at a control solution for an offshore crude oil export terminal. In the case of the proposed project, however, such a solution would entail replacement of the proposed SPM with a permanently moored FSO. The cost

[188] Lanquetin, B. 2005. "More than 30 Years' Experience with F(P)SO's and Offloading Techniques." Paper presented at the International Petroleum Technology Conference in Doha, Qatar, 21–23 November 2005.

[189] Shell Upstream Americas. January 26, 2017. *Notice to Airmen: FPSO Turritella Offload Operations Alert*. Accessed April 29, 2019 at http://www.avnotice.com/archive/160_1563.pdf.

of purchasing, retrofitting, and operating a Suezmax tanker as an FSO would be significantly higher than BWTX's intended SPM system, and would not otherwise further BWTX's business objectives. Therefore, this alternative has been rejected

7.3 Proposed Emission Standards

The NOMA application must include a review of "*a relevant proposed regulation, including all supporting information*."[190] BWTX understands that this provision was intended primarily to apply to major sources of HAP that were to be constructed (or reconstructed) during the time when EPA was in the process of proposing and promulgating regulations for the initial source of NESHAP source categories.[191] BWTX does not believe that there are any proposed regulations which can inform the alternatives analysis.

7.4 Selected Control Technology

Of the nine alternatives considered, all have been rejected save the combined work practice, which is described in detail in Section 8. Cost, non-air quality environmental impacts, and energy requirements have been evaluated for the selected control technology, and are deemed acceptable.

190 40 CFR § 63.41.

191 Cf. CAA § 112(j)(6).

Section 8
Proposed MACT Requirements

BWTX recommends the MACT requirements to implement its recommended control requirements, consistent with the level of control equivalent to that achieved by the best-controlled similar source.

A. MACT Emission Limitation

1. Liquids loaded into the cargo tanks of transport vessels shall be limited to crude oil, pipeline interface (transmix), and water. For purposes of this notice, "crude oil" shall include lease condensate.
2. The above stated owner or operator shall not permit any vessel to be loaded unless it complies with the equipment design specifications of 46 CFR § 153.282.
3. The above stated owner or operator shall not permit any vessel to be loaded unless it possesses and implements a VOC management plan consistent with the requirements specified in 40 CFR § 1043.100(b)(1), Regulation 15.6.
4. The above stated owner or operator shall conduct transfer operations in accordance with an operations manual pursuant to 33 CFR § 150.425.
5. During the initial stages of loading into each individual tank the flow rate in its branch line should not exceed a linear velocity of 1 metre/second. When the bottom structure is covered and after all splashing and surface turbulence has ceased, the rate can be increased to the lesser of the ship or shore pipeline and pumping system maximum flow rates, consistent with proper control of the system. Prior to the start of each transfer operations, the above stated owner or operator shall perform a calculation to determine the maximum cargo pumping rate which ensures compliance with this provision.
6. Each manifold flange shall be equipped with a removable blank flange. The end of each hose not connected for the transfer of oil shall be blanked off. Each part of the transfer system not necessary for the transfer operation shall be securely blanked or shut off. Prior to the removal of blanks from tanker and facility pipelines or hoses, the section between the last valve and blank shall not contain oil under pressure. Precautions to prevent spillage, including inventorying hoses with sea water at the conclusion of each loading operation, shall be implemented.

B. Monitoring Requirements

1. During each loading operation, the above stated owner or operator shall continuously monitor the transfer rate.
2. Prior to receiving a vessel at the facility, the above stated owner or operator shall conduct vetting of the vessel using a standardized vetting policy. The vetting policy shall include provisions to ensure compliance with paragraphs 2 and 3 of the control requirements of this authorization.
3. The marine loading operations are limited to products with a true vapor pressure not to exceed 11 psia at 95° F and sulfur content of 10 ppmw. The above stated owner or operator shall maintain an electronic copy of the product analysis (laboratory Certificates of Analysis, COA) from the delivering source for each crude stock/type that is loaded at the facility. As an alternative to maintaining a COA for a product, a sample test of the crude oil for TVP shall be completed prior to loading for each crude stock/type from each customer/source using methods American Society for Testing and Methods (ASTM) UOP 163-10 or ASTM D7621-14 for H_2S and converted to ppmw for comparison to the sulfur content limit. For measurement of TVP, ASTM D6377 shall be used and compared to the 11 psia limit.
4. The above stated owner or operator shall, on a monthly basis, calculate the estimated HAP emissions from crude oil loading operations during the preceding 12-month period.

C. Reporting and Recordkeeping Requirements

1. The above stated owner or operator shall notify EPA Region 6 in writing or by electronic mail of the following activities. Such notifications shall be delivered or postmarked within 30 calendar days after the date the activity takes place:
   (a) the actual date construction is commenced;
   (b) the actual date construction is completed; and
   (c) the actual date of startup of the source.
2. Records containing the information and data sufficient to demonstrate compliance with the provisions of this approval shall be maintained at an office having day-to-day operational control of the site. Such records shall be maintained for at least five years following the date the information or data is obtained.
3. The above stated owner or operator shall maintain the following records:

(a) A copy of the operational manual required under Provision B.4.

(b) A copy of the vetting policy required under Provision C.2.

4. The above stated owner or operator shall maintain a file which specifies, for each crude oil loading operation, the following information:

(a) The volume of crude oil loaded;

(b) The true vapor pressure of the crude oil loaded;

(c) The date and time of commencement and completion of the loading operation;

(d) The date and time at which submerged fill is established; and the calculated maximum allowable pumping rate and actual cargo transfer during the time period specified in Provision B.5.

(e) The results of the vetting of the vessel, to the extent necessary to establish compliance with Provision C.2.

(f) The estimated quantity of HAP emissions resulting from the loading operation;

(g) The identifier of the mooring buoy at which loading takes place (i.e., SPM1 or SPM2);

(h) The IMO registry number corresponding to the loaded vessel;

Section 9
Maintenance Activities

This section collects information which was previously submitted concerning air emissions of from maintenance activities at the proposed SPM facility, and preventative maintenance practices anticipated at the terminal.

9.1 Quantification of Emissions from Maintenance Activities

BWTX has not identified any MSS activities at the terminal that would result in emissions in excess of those expected during routine loading operations. Maintenance activities of the types that typically occur at terminals, such as pipeline pigging, meter proving, and pump maintenance, will take place at the onshore Booster station and will not give rise to emissions at the SPM terminal.

At the end of each loading operation, the floating hoses will be flushed with sea water, with some sea water entering the tanker's slop oil tanks. This work practice serves to reduce emissions from hose replacements to negligible levels.

The maintenance activity with the highest potential emission rate that BWTX has identified would be replacement of floating hoses, which would occur no more than once per year per hose string. As noted in the response to Item 7, hoses are flushed with seawater at the end of each loading operation, so hydrocarbons remaining in the hose would consist primarily of oil clinging to the elastomeric lining on the inner carcass. Emissions from draining of hoses during replacement is estimated by assuming that a volume of hydrocarbon liquids is volatilized and emitted to the air. The volume is estimated based on a clingage factor of 0.006×10^{-3} Bbl/ft^2.[192] For a 600 mm I.D. × 1000' hose string, a total wetted area of 6184 ft^2 is calculated, corresponding to a clingage volume of 1.56 gallons, or 11 lb for an assumed liquid density of 7.1 lb/gal. If this activity occurs at each of two hoses per buoy once per year, total annual emissions of 44 lb, or 0.02 tpy are expected.

[192] AP-42 Chapter 7, Table 7.1-10.

9.2 Maintenance Checklist and Pre-berthing checklist for BWTX Affiliate's Tetney Facility

Appendix A includes a maintenance checklist used at BWTX's parent company's SPM facility in Tetney, United Kingdom to ensure integrity of the SPM system. Also attached is a pre-berthing checklist for the same facility. The checklists are primarily intended to prevent safety incidents and accidental discharges of crude oil. BWTX intends to implement similar provisions at its proposed SPM facility based on the offshore weather conditions and project design.

Appendix A
Supplemental Information

SPM Buoy and Project Location Detail

Pipeline Tariff

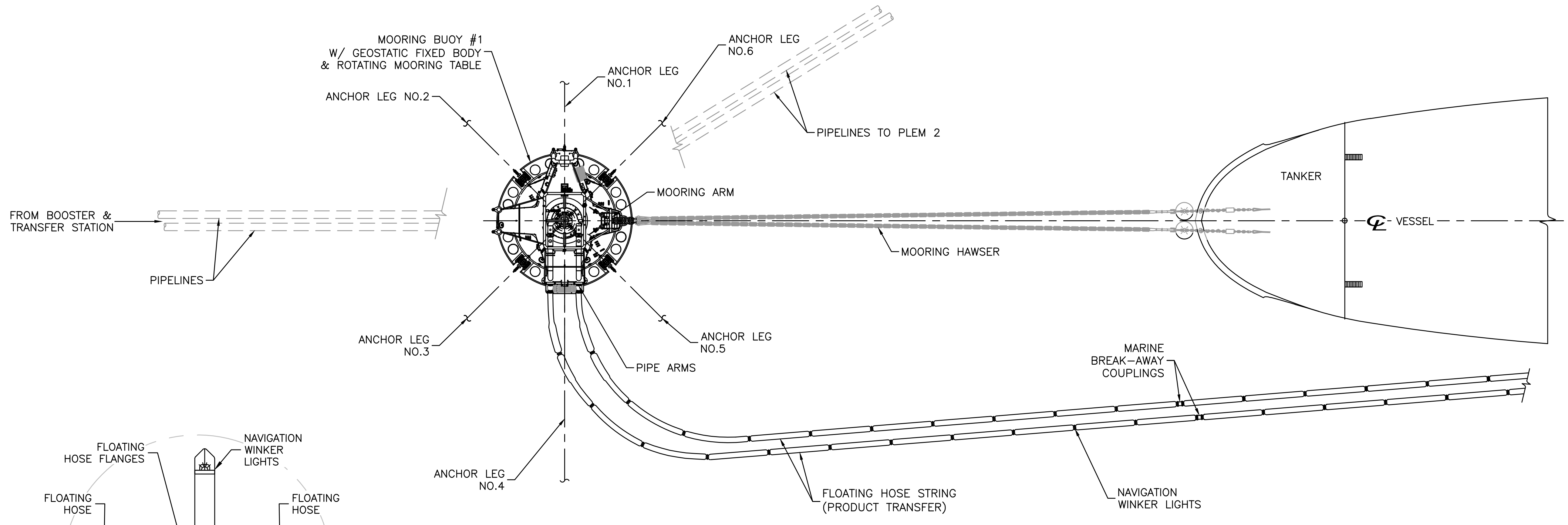
Deepwater Port License Application Excerpts

Correspondence with Classification Society

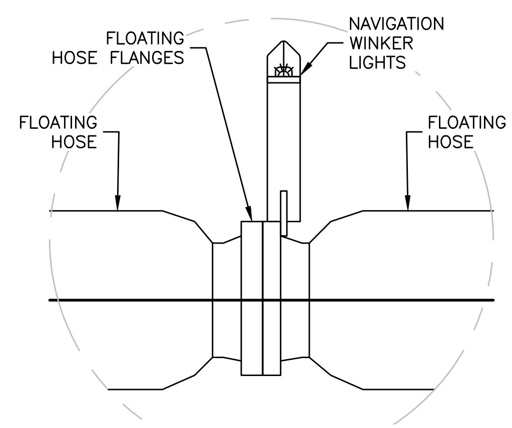
Correspondence with Control Equipment Vendor

Tetney Facility Maintenance Checklist

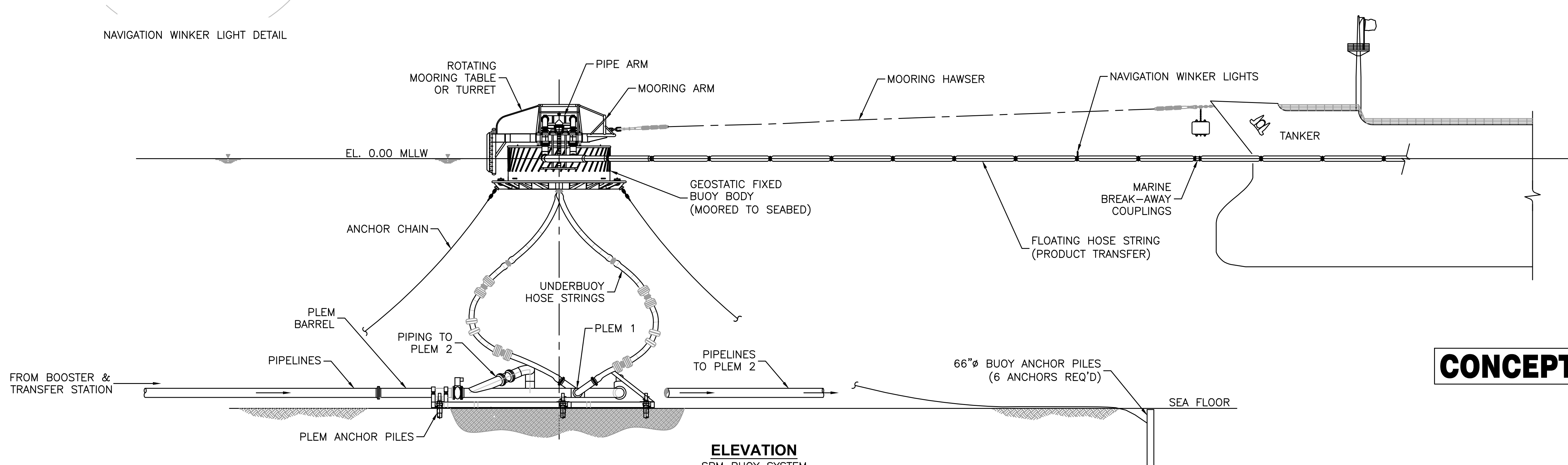
Tetney Facility Pre-Berthing Checklist



PLAN
SPM BUOY SYSTEM ARRANGEMENT



NAVIGATION WINKER LIGHT DETAIL



ELEVATION
SPM BUOY SYSTEM

CONCEPTUAL

CONFIDENTIAL BUSINESS
PROPRIETARY INFORMATION
EXEMPT FROM FOIA

NO.	DESCRIPTION	DATE	APPR
A	ISSUED FOR REVIEW	MM/DD/YY	-

ISSUED FOR REVIEW

PHILLIPS 66

SEAL

BLUEWATER
TERMINAL LLC

CLIENT

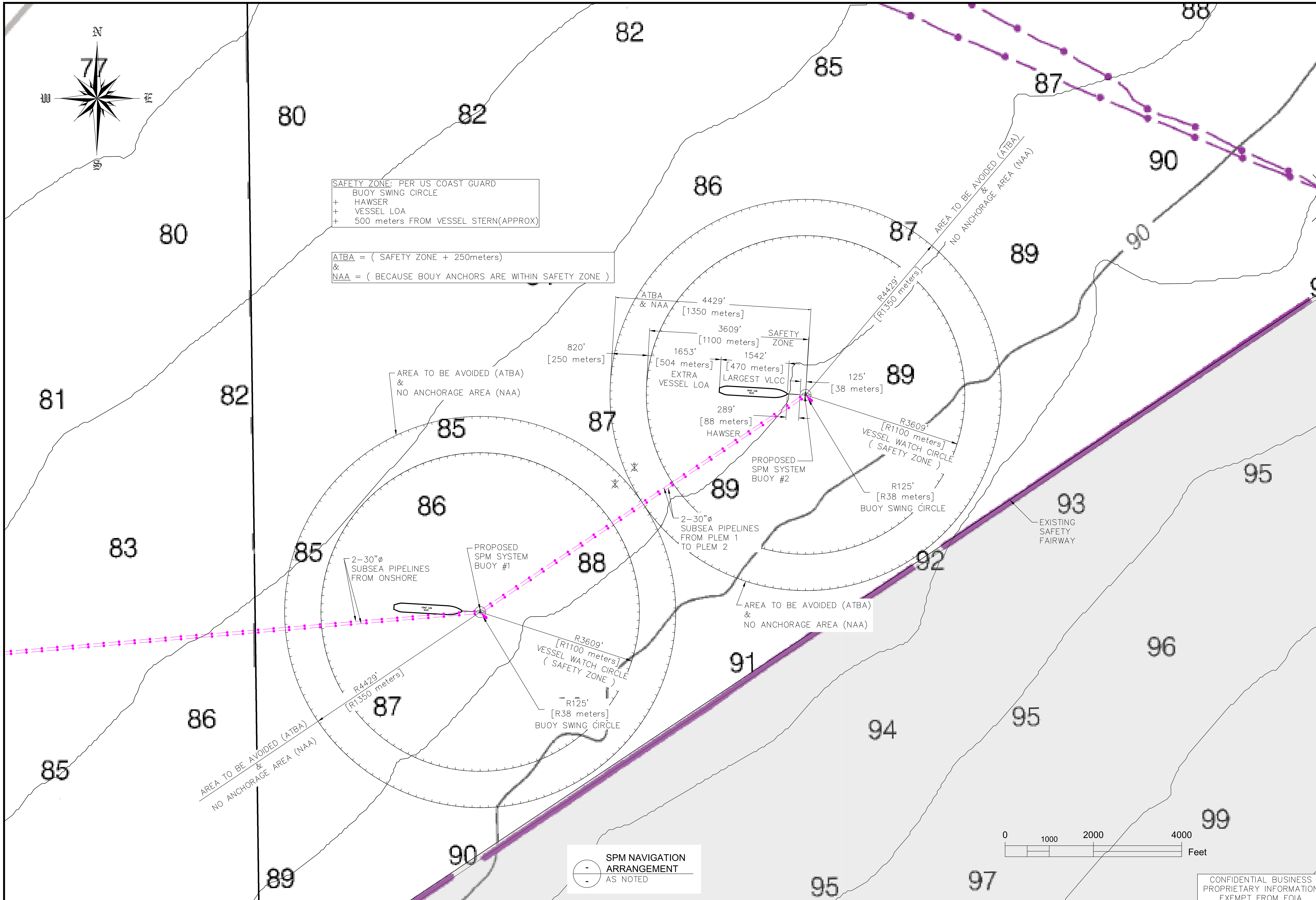
BLUEWATER SPM PROJECT
ARANSAS PASS, TEXAS

SPM BUOY 1 SYSTEM ARRANGEMENT

LLOYD ENGINEERING, INC
STATE OF TEXAS, USA
LICENSE NO. F-002846

DESIGN BY:	JSL
DRAWN BY:	RC
DATE:	OCT 2018
SCALE:	AS NOTED @ 22"X34"
SHEET:	12 OF 15
DRAWING NO:	12
REV. ----	

FILE NAME: L:\LEI Projects\P66\SPM Harbor Island\6.0 Drawings\Conceptual\12 SPM BUOY 1 SYSTEM ARRANGEMENT.dwg PLOTTED: 2/28/2019 2:37:36 PM USER: RALF CABALLERO



SPM NAVIGATION ARRANGEMENT
AS NOTED

CONFIDENTIAL BUSINESS PROPRIETARY INFORMATION EXEMPT FROM FOIA

FILE NAME: I:\ei projects\P66\spm harbor island\6.0 drawings\conceptual\6 DEEPWATER PORT NAVIGATION ARRANGEMENT.dwg PLOTTED: 5/10/2019 2:23:44 PM USER: RALF CABALLERO

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ISSUED FOR PERMIT

PHILLIPS 66

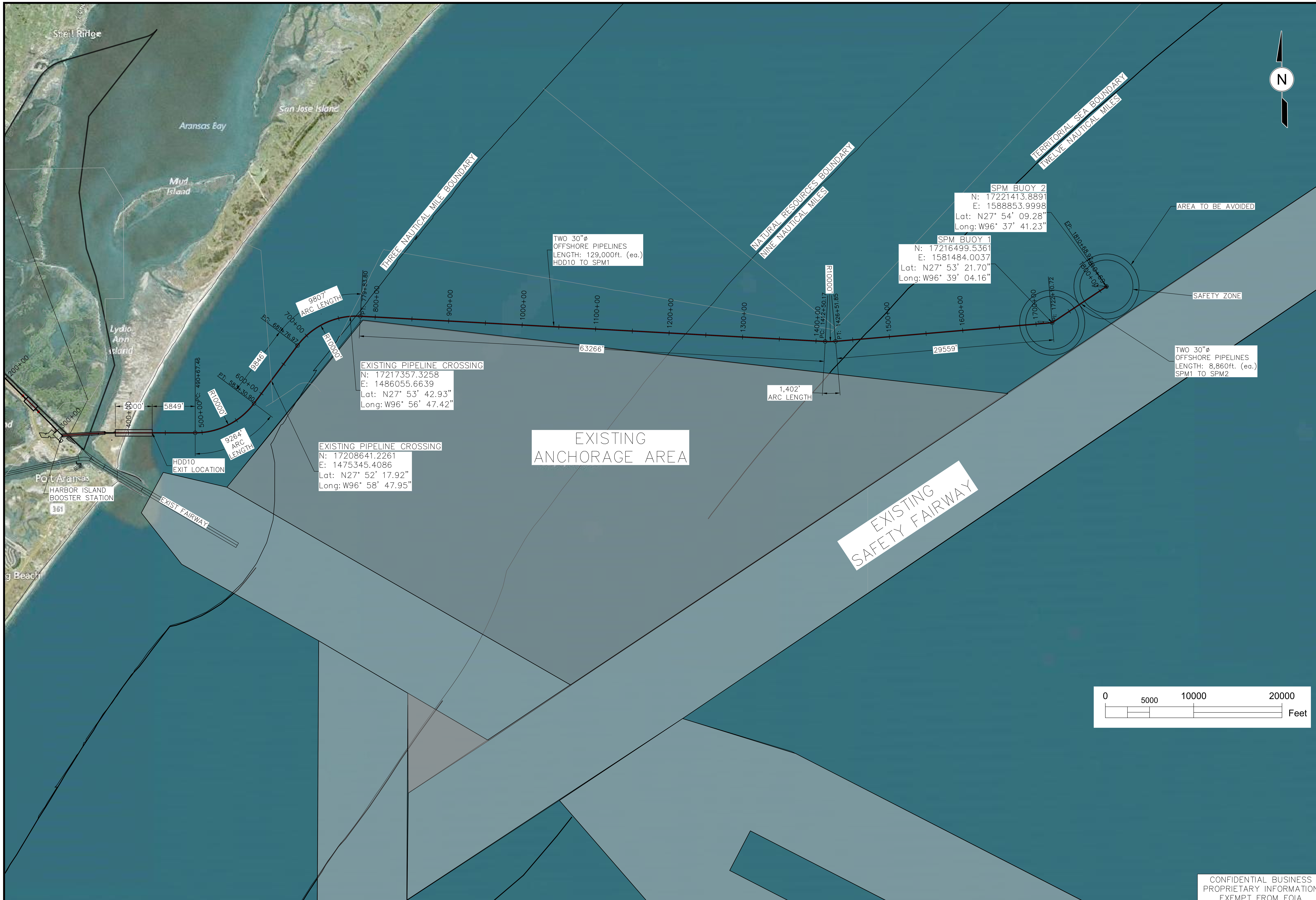
BLUEWATER TEXAS TERMINAL, LLC

BLUEWATER SPM PROJECT
ARANSAS PASS, TEXAS

DEEPWATER PORT NAVIGATION ARRANGEMENT

LLOYD ENGINEERING, INC
STATE OF TEXAS, USA LICENSE NO. F-002846

DESIGN BY:	JSL
DRAWN BY:	RC
DATE:	MAY 2018
SCALE:	AS NOTED @ 22"X34"
SHEET:	6 OF 22
DRAWING NO:	6
REV. A	



ISSUED FOR PERMIT

NO.	DESCRIPTION	DATE	APPR
A	ISSUED FOR PERMIT	- - -	-

PHILLIPS 66

BLUEWATER TEXAS TERMINAL, LLC

BLUEWATER SPM PROJECT
ARANSAS PASS, TEXAS

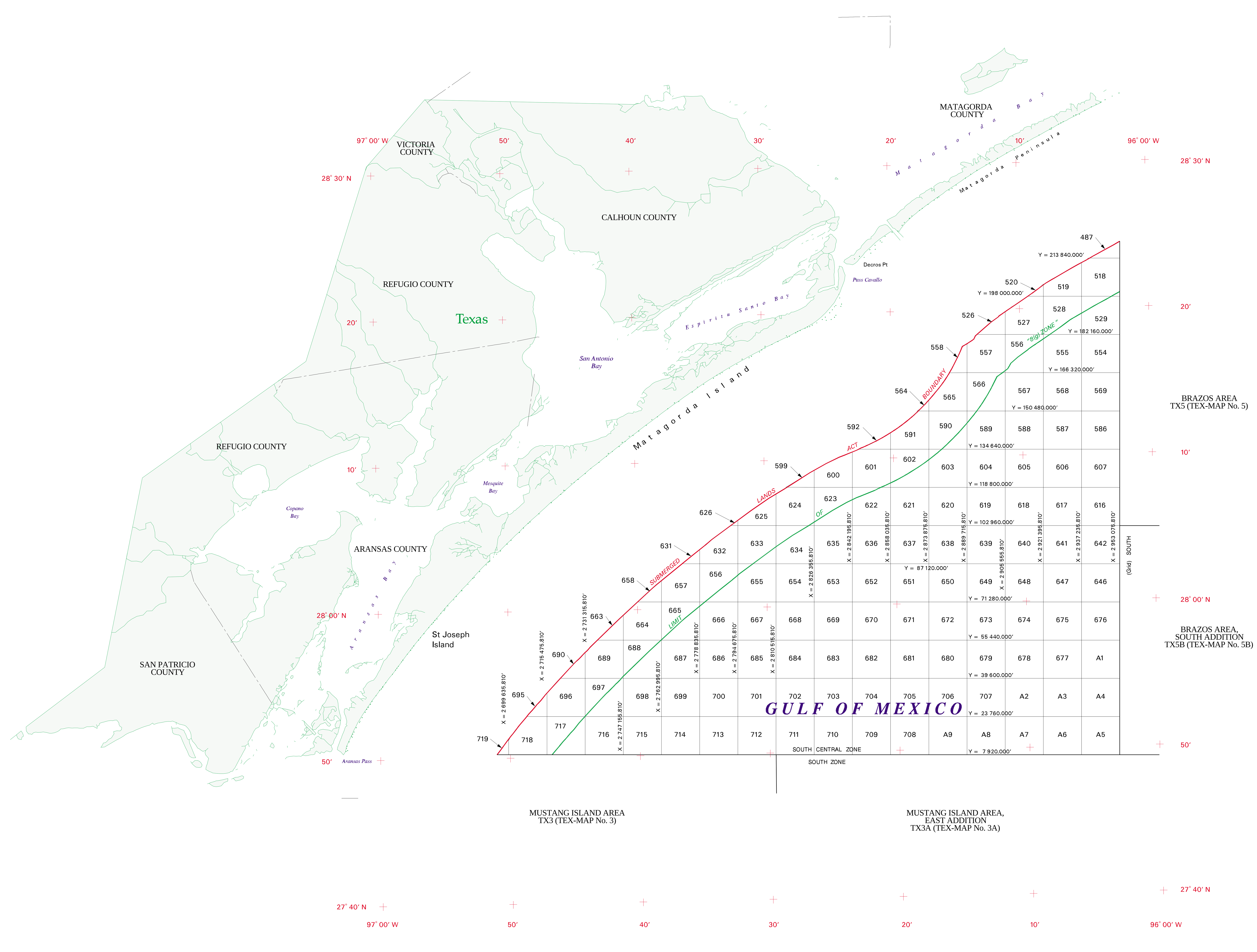
OFFSHORE LAYOUT

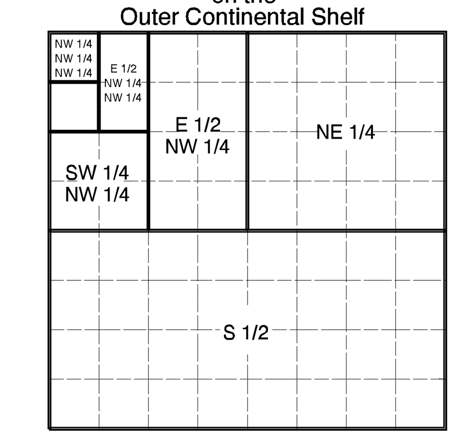
LLOYD ENGINEERING, INC
STATE OF TEXAS, USA
LICENSE NO. F-002846

DESIGN BY:	JSL
DRAWN BY:	RC
DATE:	MAY 2018
SCALE:	AS NOTED @ 22"X34"
SHEET:	4 OF 22
DRAWING NO:	4
REV. A	

CONFIDENTIAL BUSINESS PROPRIETARY INFORMATION EXEMPT FROM FOIA

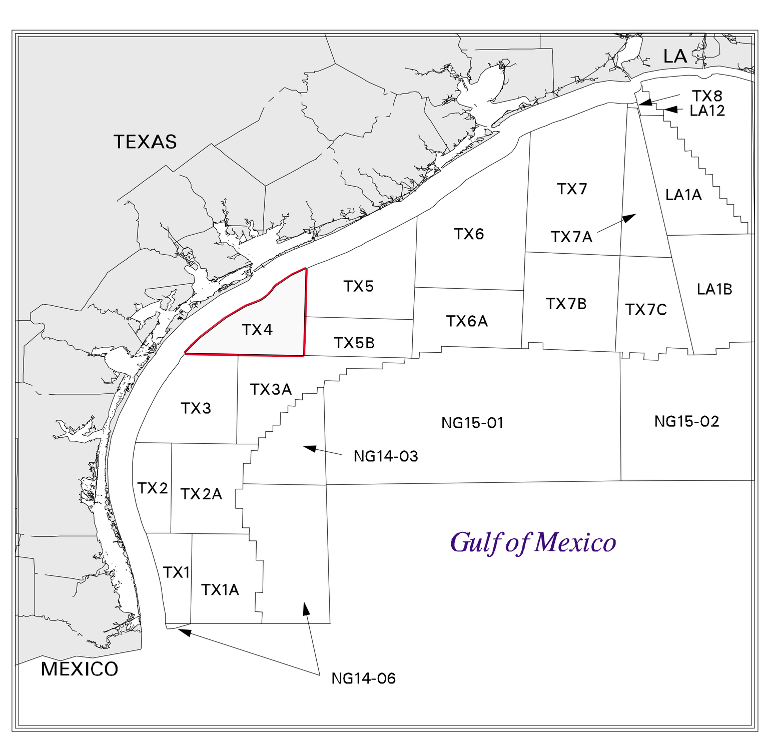
FILE NAME: I:\ei projects\P66\spm harbor island\6.0 drawings\conceptual\4 OFFSHORE LAYOUT.dwg PLOTTED: 5/10/2019 2:22:23 PM USER: RALF CABALLERO





Typical method of subdivision of the regular blocks, each subdivision being an aliquot part of the total, based on midpoint subdivision throughout.

TEXAS
GULF COAST INDEX



All blocks are based on the Texas (Lambert) Plane Coordinate System, South Central Zone, with X origin = 2,000,000' at 99° 00' W and Y origin = 0.00' at 27° 50' N.

Regular blocks are 15,840 feet on a side and contain 5,760 acres.

Onshore planimetric base compilation is from USGS 1:100 000 Digital Line Graph (DLG) Files.

This revised map supersedes leasing map MATAGORDA ISLAND AREA, TEX-MAP No. 4, approved 16-JUL-1954, and TX4 revised 01-SEP-1999.

The Submerged Lands Act Boundary and Limit of "8(g) Zone" lines depicted hereon reflect the official federal position for Submerged Lands Act and OCS Lands Act purposes. The areas of the fractional blocks abutting these lines have been determined and are as depicted on the Supplemental Official OCS Block Diagrams (SOBD's). Consult the SOBD's for official descriptions and approval dates.

Copies of these diagrams and other information may be obtained at the appropriate MMS OCS Region.

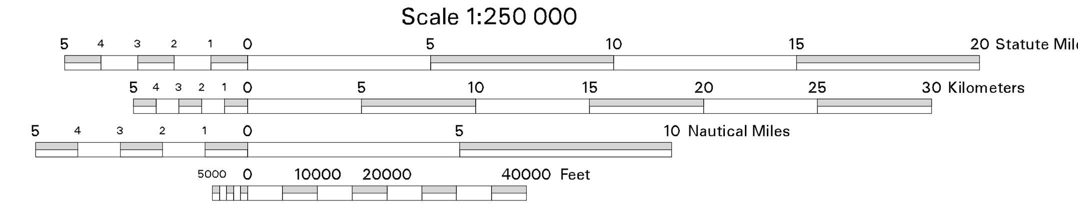
UNITED STATES DEPARTMENT OF THE INTERIOR
MINERALS MANAGEMENT SERVICE

OUTER CONTINENTAL SHELF LEASING MAP

TEXAS

NORTH AMERICAN DATUM OF 1927

Scale 1:250 000



This diagram is prepared in accordance with 30 CFR 256.8

For the Director

Chief, Leasing Division, Mapping and Boundary Branch

Denver, Colorado   Date 01-NOV-2000

Revised

BWTX-20200501_0122

GRAY OAK PIPELINE, LLC

PIPELINE TARIFF
Containing Rules and Regulations
Governing the Intrastate Transportation of
Crude Petroleum By Pipeline

The Rules and Regulations published herein apply only under tariffs making specific reference to this tariff; such reference will include supplements hereto and successive issues hereof. Specific Rules and Regulations published in individual tariffs will take precedence over Rules and Regulations published herein

Operated by Phillips 66 Pipeline LLC - P-5 Operator ID: 663865
T-4 Permit # 09879

The provisions published herein will, if effective, not result in an effect on the quality of the human environment.

ISSUED: February 28, 2020 **EFFECTIVE: April 1, 2020**

Issued by:
Todd Denton, President
Gray Oak Pipeline, LLC
P.O. Box 421959
Houston, TX 77242-1959

Compiled by:
Alan Fairwell, Director, Tariffs
P.O. Box 421959
Houston, TX 77242-1959
PH: 832-765-1608
Fax: 918-977-8537

20. Definitions – Continued

"**Shipper**" means the party who contracts with Carrier for the transportation of Crude Petroleum under the terms of Carrier's tariffs.

"**Shipper's Inventory**" means total Receipts of Crude Petroleum, by grade, from a single Shipper less Deliveries to that Shipper's Consignees.

"**Specified Grade**" means Crude Petroleum meeting certain specifications designated by Carrier for such grade of Crude Petroleum.

"**Tender**" means to physically deliver, or cause to be delivered, Crude Petroleum, by or on behalf of a Shipper to Carrier for transportation from an Origin Point to the Destination Point, in accordance with Carrier's confirmed Nominations schedule for Crude Petroleum Receipts and tariffs, to the custody transfer point for Receipt into the Pipeline at the Origin Point.

"**TSA**" means a Transportation Service Agreement executed pursuant to an open season of Carrier.

21. Quality Specifications; Restrictions

Carrier will receive Crude Petroleum only through its facilities at an Origin Point. Carrier reserves the absolute right to reject on a not unduly discriminatory basis (without limitation), and Shipper shall not deliver to Carrier without Carrier's written consent, any or all of the following:

(1) Crude Petroleum that is not readily susceptible to transportation through Carrier's existing facilities;
(2) Crude Petroleum having a true vapor pressure in excess of 11.0 pounds per square inch absolute (psia) at 100°F, using ASTM D6377 methodology, or that would result in Carrier's non-compliance with any federal, state, or local requirements regarding hydrocarbon emissions;
(3) Crude Petroleum with a Reid Vapor Pressure in excess of 9.5 psia;
(4) Crude Petroleum having an API (American Petroleum Institute) gravity in excess of 78.9°;
(5) Crude Petroleum having an API gravity less than 36°;
(6) Crude Petroleum having a sulfur content weight % greater than 0.50%;
(7) Crude Petroleum exceeding 10 ppm hydrogen sulfide (H_2S), using ASTM D5705-15 methodology;
(8) Crude Petroleum having basic sediment, water and other impurities of greater than one (1) percent, with a maximum of three tenths (0.3) percent free water;
and
(9) Crude Petroleum that does not meet the specifications of the connecting carriers.

Carrier reserves the right to reject any Crude Petroleum offered for transportation other than good and merchantable Crude Petroleum of acceptable character or that, when measured and tested by Carrier or Carrier's representative at the Origin Point, meets all of the qualifications set forth in this tariff. The presence of contaminants in Crude Petroleum, including but not limited to chemicals such as chlorinated and/or oxygenated hydrocarbons and/or lead or iron shall be reason for Carrier to reject any Crude Petroleum. Crude Petroleum containing such contaminants shall be deemed to be unmerchantable, and a Shipper who offers contaminated Crude Petroleum shall be deemed to have breached the warranty and representations set forth in Item No. 75 herein.

2.7 Tier V – Evaluation of Design Alternatives

During the Tier IV screening analysis, the Applicant identified two alternatives which fulfilled the purpose and need of the proposed Project to be carried forward for analysis. As such, Tier V of the alternatives analysis was conducted to evaluate design alternatives to determine the most practicable design of the necessary components to allow for the for the safe export of crude oil while minimizing environmental impacts to the maximum extent practicable. The Tier V analysis consists of the screening of alternative designs including:

- Deepwater Port Design Alternatives
- SPM Buoy Anchoring Alternatives

The following sections detail the design alternatives analysis conducted for the above described components. The results of the Tier V analysis will be the proposed design to be carried forward for both alternatives described as a result of the Tier IV analysis.

2.7.1 Deepwater Port Design Alternatives

The Applicant evaluated potential DWP design alternatives to determine the DWP design that best fulfills the purpose and need of the Project while minimizing environmental impacts to the maximum extent practicable. As defined by the DWPA, the term "deepwater port" is any fixed or floating manmade structure other than a vessel, or any group of such structures, that are located beyond State seaward boundaries and that are used or intended for use as a port or terminal for the transportation, storage, or further handling of oil or natural gas for transportation to or from any State. To meet the previously described Project objectives, the DWP design must allow for the simultaneous loading of VLCCs. As such, the DWP design configurations analyzed were those capable of allowing for the simultaneous loading of VLCCs. For this analysis, the following DWP design alternatives were considered:

- DWP Design Alternative 1: Two SPM Buoy System Design
- DWP Design Alternative 2: Dual Berth Fixed Platform Design

The analysis of potential DWP design alternatives was based upon seven screening criteria including:

- DWP Design Criteria 1: Minimizes the potential for interference with natural processes
- DWP Design Criteria 2: Maximizes berth availability
- DWP Design Criteria 3: Minimizes personnel required for operation
- DWP Design Criteria 4: Minimizes length of construction schedule
- DWP Design Criteria 5: Minimizes maintenance requirements
- DWP Design Criteria 6: Minimizes seabed and above water footprint
- DWP Design Criteria 7: Minimizes chances of accidental collision damage

The following section discusses each of the DWP design alternatives ability to fulfill the criteria listed above.

<u>DWP Design Alternative 1: Two SPM Buoy System Design</u>

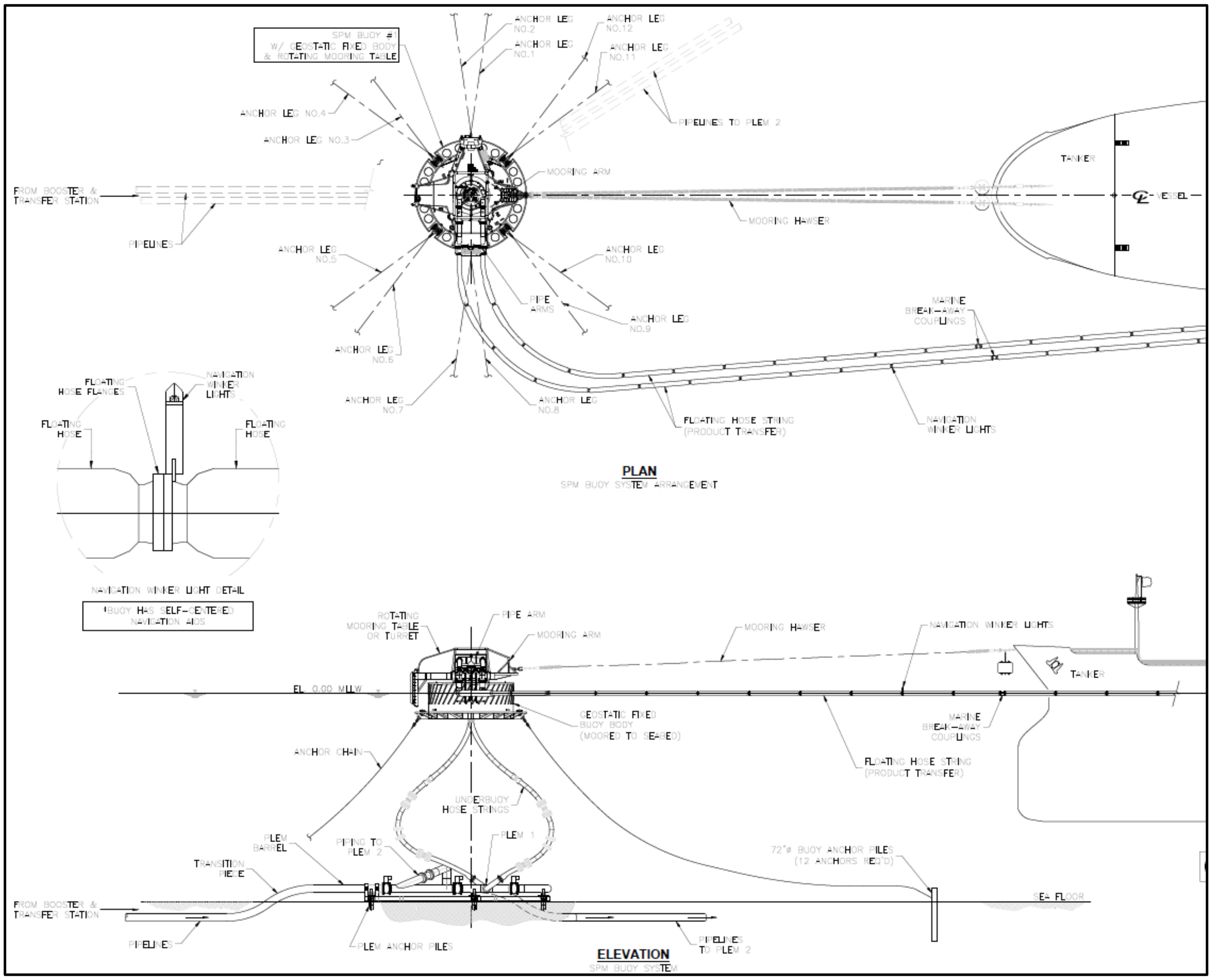
A SPM buoy is a floating buoy anchored offshore to allow for the handling of liquid cargo, such as crude oil, for the loading and/or unloading of vessels. SPM buoys are connected to shore-based facilities using offshore pipeline infrastructure for the loading and/or unloading of liquid cargo from vessels of large capacity, such as a VLCC.

SPM buoys are moored to the seabed using a mooring arrangement which includes anchors and anchor chains. Mooring arrangements are such that it allows the buoy to move freely within defined limits based on vessel conditions, wind, waves, and currents. The body of the SPM buoy system floats above the water surface and consists of a rotating table which connects to the vessels through a hawser arrangement. The cargo transfer from the SPM buoy system and the vessel begins with a pipeline end manifold (PLEM) located on the seabed directly under the

SPM buoy. The PLEM serves as the connection point between offshore pipelines and the SPM buoy. A series of floating hose strings connect the SPM buoy to the vessel allowing for the transfer of liquid cargo.

Refer to Figure 2-22 for a depiction of the general arrangement of an SPM buoy system. Refer to Figure 2-23 for a depiction of a vessel moored at an SPM buoy system.

Figure 2-22: Single Point Mooring Buoy System General Arrangement



Source: LEI Engineering Drawings

SPM buoy systems are capable of operating efficiently in rough seas and are not sensitive to directional changes of wind, waves, and currents. Due to vessels being moored to the SPM buoy via bow lines, vessels “weather-vane” around the buoy to stay head-on during various weather, wind, wave, and current forces. The ability to load vessels during various offshore conditions allows for greater terminal utilization and operational efficiencies.

Below is a general overview of how a SPM buoy system works.

- Vessels would approach the SPM buoy
- Support vessels are used to safely navigate vessels into position for mooring to the SPM buoy,
- Vessels are moored to the SPM buoy for the loading of cargo,

- Cranes located on the vessel are used to lift floating product transfer hoses for connection to the vessel manifold,
- Once connections are made, valves are operated from shore-based facilities to initiate the transfer of cargo to the vessel,
- Once vessel loading is complete, floating product transfer lines are disconnected from the vessel manifold and lowered using cranes fixed on the vessel.

An SPM buoy system is an unmanned system remotely operated from a land-based facility. The use of support vessels for the SPM buoy operations is limited to the mooring/unmooring and product hose connection and disconnection. As such, the use of an SPM buoy system for the loading of vessels reduces operational dependency of onsite personnel and support vessels.

The onsite construction and installation of the two SPM buoy systems is estimated to require 2 months. This includes the transport of the prefabricated SPM to the designated location, installation of anchoring systems, installation of the PLEM, and connection to sub-sea pipeline infrastructure.

Figure 2-23: Single Point Mooring Buoy System in Operation

Source: Phillips 66 Tetney Buoy

DWP Alternative 2: Fixed Platform Design

The design and functionality of a fixed platform for the offshore loading of vessels is similar to that of a fixed dock or terminal used at inland port facilities. The use of an offshore fixed platform for the loading of VLCCs would require an approximate 25,000 square ft. platform equipped with marine loading arms and dock supporting infrastructure, mooring dolphins, and catwalks. The offshore fixed platform would be connected to shore-based facilities using sub-sea/offshore pipeline infrastructure for the loading of vessels.

The fixed offshore platform would be supported by multiple large-diameter pile arrangements installed on the seafloor and installed to sufficient depths to ensure structural integrity. Additionally, the mooring of vessels at a fixed platform requires the installation of mooring dolphins and catwalks to safely secure vessels during loading operations. Below is a general overview of the processes required for the loading of vessels at an offshore fixed platform.

- Vessels would approach the offshore fixed platform.
- Support vessels are used to safely navigate vessels for mooring at the fixed platform.
- A combination of platform personnel and support vessels aid in the mooring of the vessel.
- Marine loading arms are connected to the vessel manifold.
- Fixed platform personnel operate valves for the transfer of crude oil to the vessel.
- Once the vessel is fully loaded, marine loading is disconnected from the vessel.
- A combination of platform personnel and support vessels aid in the unmooring of the vessel.
- Support vessels are used to safely navigate vessels away from the fixed platform.

The fixed offshore platform is a manned system requiring the use of onsite personnel for operations. Additionally, a fixed platform requires the use of support vessels which are required for vessel approach, mooring/unmooring, and departure product hose connection and disconnection. As such, the use of a fixed platform requires the transport of onsite personnel to and from the location of the offshore fixed platform and the necessary facilities to support the health and safety of onsite personnel.

The onsite construction of a fixed platform is estimated to require 4 months. This includes the transport of the prefabricated materials to the designated location, installation of platform supporting piles, mooring dolphins, installation marine loading arms, and connection to sub-sea pipeline infrastructure.

DWP Design Criteria 1 - Minimizes the Potential for Interference with Natural Processes

Natural processes such as wind, waves, and currents exert forces on and below the water surface. The minimization of the overall structures above and below the water surface results in minimal interference with forces exerted by natural processes. The Two Buoy System Design is smaller than that of the Dual Berth Fixed Platform Design. Additionally, the Two Buoy System Design would be supported in location by tension chains designed to allow for movement with natural forces. A rigid fixed dock platform requires the installation of multiple rigid pile structures both above and below the water surface. Additionally, vessels moored to a SPM buoy system are not sensitive to directional changes of wind, waves, and currents as the vessel is free to “weather-vane” around the SPM buoy to stay head-on during various weather, wind, wave, and current forces.

DWP Design Criteria 2 – Berth Availability

Berth availability and ability to safely moor a vessel at an offshore DWP is dependent on the environmental conditions such as weather, winds, and waves as well as the DWP’s design capabilities for accommodating the safe mooring of vessels in such conditions. Variations of wind and currents occur seasonally within the Gulf of Mexico. As such a DWP system that allows for the accommodation for various conditions allows for the safe mooring of vessels, and thereby greater efficiency and utilization of the DWP. The use of SPM buoy systems allows for vessels to "weather-vane" around the buoy to stay head-on during various weather, wind, wave, and current forces, whereas a fixed dock structure requires the vessels be positioned in a designated manner to allow for loading operations. The ability of the SPM buoy systems to accommodate for the various offshore conditions allows for greater berth availability.

DWP Design Criteria 3 – Personnel Required for Operation

An SPM buoy system is an unmanned system remotely operated from a land-based facility. The use of support vessels for the SPM buoy operations is limited to the mooring/unmooring and product hose connection and disconnection. The fixed offshore platform is a manned system requiring the use of onsite personnel for operations. Additionally, a fixed platform requires the use of support vessels for the vessel approach, mooring/unmooring, and departure product hose connection and disconnection. As such, the use of a fixed platform requires the transport of onsite personnel to and from the location of the offshore fixed platform and the necessary facilities to support the health and safety of onsite personnel. The optimal DWP design would be one that minimizes potential safety hazards through the minimization of the number of onsite personnel required at the DWP during operations. As such, the use of an SPM buoy system for the loading of vessels reduces operational dependency of onsite personnel and support vessels, thereby minimizes potential health and safety exposures.

DWP Design Criteria 4 – Length of Construction Schedule

A longer onsite construction timeframe results in greater disturbance of the marine environment and impacts to benthic habitats, underwater noise disturbance, suspension of sediments, and prolonged impacts to water quality. The onsite construction of a fixed platform is estimated to require 4 months whereas the onsite construction of two SPM buoy systems is estimated to require 2 months. As such, the construction of the SPM buoy systems minimizes the length of onsite construction required for the installation of a DWP.

DWP Design Criteria 5 – Maintenance Requirements

The maintenance of a fixed berth will be greater than an SPM buoy due to its multiple fixed components such as loading arms, valves, and controls equipped on the deck of the platform. The greater amounts of maintenance associated with an offshore platform require prolonged hazard exposure to personnel in an offshore environment, thereby presenting significant safety concerns.

DWP Design Criteria 6 – Seabed and Above Water Footprint

The SPM buoy system would provide a smaller footprint on the seabed and above water than a fixed platform which in turn would result in less environmental impacts. Each SPM buoy system would consist of multiple components including a PLEM, a floating buoy, mooring hawsers, floating hoses, and sub-marine hoses. The PLEM system would be an approximate 65 ft. by 34 ft. steel frame structure positioned directly beneath the proposed SPM buoy system and would be anchored directly to the seafloor with anchor piles. Above the water, each SPM will be approximately 1,000 square ft. and approximately 25 ft. in height. A fixed platform with the ability to load VLCCs would require an approximate 25,000 square ft. platform with mooring dolphins with catwalks connecting each structure. Additionally, a fixed platform would likely require a helipad to transport personnel to and from the structure for maintenance and operations. As such, for the purposes of simultaneously loading VLCCs in an offshore environment, the use of SPM buoy systems requires less surface area, subsurface area, and impacts to the seafloor.

DWP Design Criteria 7 – Accidental Collision Damage

Based on conversations with major SPM buoy venders, SPM buoys under service contracts experience minor, if any, damage as a result of operations. An SPM buoy system is anchored to the seafloor by chains which are set at appropriate tensions to allow for the flexibility and movement of the SPM buoy system in response to various offshore conditions. A fixed platform is supported by pile structures which are rigid structures. In the situation of an accidental collision, the SPM buoy design allows for the dissipation of forces exerted by the vessel whereas rigid structures associated with a fixed platform absorb forces. As such, damages as a result of an accidental collision would be less for an SPM buoy than that of a fixed platform.

Deepwater Port Design Alternatives Analysis Summary

The analysis of the DWP design alternatives was conducted based on their ability to fulfill the necessary design criteria and minimize environmental impacts to the maximum extent practicable. The results of the analysis conducted for the DWP design alternatives are presented in Table 2-24.

Table 2-24 Deepwater Port Design Alternatives Decision Matrix

Screening Criteria	DWP Design Alternative 1: Two SPM Buoy System	DWP Design Alternative 2: Dual Berth Fixed Platform Design
DWP Design Criteria 1: Minimizes the potential for interference with natural processes	✓ SPM buoy design allows for moored vessels to accommodate for existing natural processes	X Fixed platform design consists of rigid fixed structures incapable of accommodating for various offshore processes once installed
DWP Design Criteria 2: Maximizes berth availability	✓ Vessel is allowed to freely weathervane around the SPM buoy	X Vessel remains fixed to platform and mooring structures
DWP Design Criteria 3: Minimizes personnel occupancy required	✓ Un-manned system (excluding the assist tugs during berthing and de-berthing)	X Requires personnel to be onsite the fixed platform during operations
DWP Design Criteria 4: Minimizes length of construction schedule	✓ 2-month timeframe of disturbance of the marine environment	X 4-month timeframe and disturbance of the marine environment
DWP Design Criteria 5: Minimizes maintenance requirements	✓ Shorter timeframe of required maintenance	X Longer timeframe of required maintenance
DWP Design Criteria 6: Minimizes seabed and above water footprint	✓ Smaller footprint on the seabed and above water	X Larger footprint on the seabed and above water
DWP Design Criteria 7: Minimizes chance of accidental collision damage	✓ Chains to the seabed will cause less damage	X Rigid dolphins and platform of a fixed dock structure will cause more damage
Evaluation Score	**7**	0
Selected as Preferred Alternative	**Yes**	No

Tier V – Deepwater Port Design Alternatives

Based on the results of the Tier V – Deepwater Port Design Alternatives analysis, as presented in Table 2-24, the use of the SPM buoy systems alternative was determined to be the most practicable DWP design alternative to be carried forward.

Date: Monday, 07 May 2018

Lloyd Engineering, Inc.
6565 West Loop South, Suite 708
Houston, TX 77401

Attention: Stan Lloyd – President

Subject: ABS Rules for Building and Classing Single Point Moorings – 2014 (updated March 2018)

Dear Sir,

Relative to your email dated 6 May 2018 inquiring whether ABS Rules for Building and Classing Single Point Moorings contain requirements or provisions for vapor control systems on SPM's, please be advised as follows:

The ABS SPM Rules contain requirements for fluid transfer systems on Single Point Moorings. The fluid transfer system includes the pipeline end manifold (PLEM), riser, product swivels and floating hoses. These Rules do not include requirements for vapor control systems.

We have also checked our records of Single Point Moorings recently classed by ABS and have verified that none have been fitted with vapor control systems

If you have any questions, please do not hesitate to contact the undersigned.

Regards,

for C. [signature]

Bret Montaruli
Vice President and Chief Engineer

From: [redacted] Terry <[redacted]@johnzink.com>
Sent: Friday, April 26, 2019 4:52 PM
To: Dave, Chaitali R <[redacted]@p66.com>
Cc: [redacted] <[redacted]@johnzink.com>
Subject: [EXTERNAL]RE: Confidential - Crude Oil Loading/Unloading Control Equipment

Chaitali –

We have not implemented a vapor combustion solution for a single point mooring project, though we have performed an engineering study on this type of application and placed considerable engineering horsepower behind it. I am not personally aware of any SPM vapor combustion systems in service for a loading application in US waters.

The end control device in such an instance, along with a vapor blower package suitable for transferring the vapors generated from such an operation, could be placed on an offshore platform or onshore depending upon the economics of each scenario. Perhaps a more complicating factor is what the US Coast Guard will allow in terms of the distance from the vessel to a Dock Safety Unit which contains the equipment necessary to assure a safe loading operation. Generally speaking, the SPM does not provide adequate space to install a DSU; however, the USCG prefers to see the DSU located as close to the vessel as reasonably possible.

I have been at [redacted] for the majority of this past week, so I apologize for my delayed response. If you are interested in discussing further next week, please feel free to let me know.

Best regards,
Terry

From: Dave, Chaitali R <[redacted]@p66.com>
Sent: Wednesday, April 24, 2019 4:00 PM
To: [redacted] Terry <[redacted]@johnzink.com>
Subject: RE: Confidential - Crude Oil Loading/Unloading Control Equipment

Sent by an external sender. Use caution opening attachments, clicking web links, or replying unless you have verified this email is legitimate.

Have you designed and implemented vapor combustion solutions for single point mooring type projects?

Regards,
Chaitali

From: [redacted] Terry <[redacted]@johnzink.com>
Sent: Tuesday, April 16, 2019 8:35 AM
To: Dave, Chaitali R <[redacted]@p66.com>
Cc: [redacted] <[redacted]@johnzink.com>
Subject: [EXTERNAL]RE: Confidential - Crude Oil Loading/Unloading Control Equipment

Chaitali –

We had some interest in the market for the ACE technology some time ago; however, it was never applied in practice. We have also fielded inquiries for single point mooring applications, but again, no company who has initially expressed interest in such an application has moved forward with a new project.

Most recently, we have seen a significant uptick in interest for vapor control solutions on offshore platforms in the Gulf of Mexico. We have performed some fairly detailed upfront engineering services for this type of application. The US market is most interested in vapor combustion solutions for this type of application.

Best regards,
Terry [redacted]

From: Dave, Chaitali R <[redacted]@p66.com>
Sent: Tuesday, April 16, 2019 7:20 AM
To: [redacted] Terry <[redacted]@johnzink.com>
Subject: RE: Confidential - Crude Oil Loading/Unloading Control Equipment

Sent by an external sender. Use caution opening attachments, clicking web links, or replying unless you have verified this email is legitimate.

Hello Terry,

I am interested in seeing what the history of the vapor control systems is applied offshore to collect and manage vapors off loading/unloading vessels through a single point mooring system such as the ACE system which described in one of your marketing materials (slide 21). Where has this type of system been applied? How many projects/locations? What is the operating history?
Any issues with the vapor collection through a spm system and any issues with water condensing in the offshore pipelines?

Regards,

Chaitali Dave
[redacted]
Phillips 66 Company
[redacted]

From: [redacted] Terry <[redacted]@johnzink.com>
Sent: Tuesday, April 16, 2019 7:13 AM
To: Dave, Chaitali R <[redacted]@p66.com>
Cc: [redacted] <[redacted]@johnzink.com>
Subject: [EXTERNAL]RE: Confidential - Crude Oil Loading/Unloading Control Equipment

Chaitali –

Thank you for your interest in John Zink. Indeed we do manufacture vapor control systems handling vapor generated from crude oil loading operations, and in fact, we have manufactured several systems for Phillips 66 over the years in this capacity. Though our technologies may be applied offshore, the very large majority of these systems are based onshore handling vapors generated during marine vessel loading operations (mainly crude oil, refined/semi-refined products, alcohols, and other petrochemicals).

Perhaps you could give me some insight regarding your interest in our products. Are you in need of a system for a specific application? If so, I can get you in touch with an applications engineer who can guide you through this process.

Best regards,

Terry [redacted] | [redacted] Director | Vapor Control Systems
John Zink Company LLC
[redacted]

EOMPS Maintenance Task Sheet

Diver 7

Divers

Unit	Sub-Unit	Description	Completed
PLEM	Structure	Visual inspection of exposed sections for corrosion/mechanical damage.	
Sub Sea Hoses	Hoses	Visual integrity check of hose body, flanges, bolts & gaskets.	
Sub Sea Hoses	Floats	Visual inspection for position, condition and security.	
Sub Sea Hoses	Drag Chains	Visual inspection for position, condition and security.	
Sub Sea Hoses	Umbilicals	Visual inspection for position, condition and security.	
Sub Sea Hoses	Configuration	Inspect sub-sea hose string’s configuration and report to Tetney.	

OK?

Remarks

EOMPS Maintenance Task Sheet

Unit	Sub-Unit	Description	Completed

SHII 7

SHII

Unit	Sub-Unit	Description	OK?
Monobuoy Main Body	Structure	Check Monobuoy Draft - (NB Design draft = 3.3m).	
Monobuoy Main Body	Centre Swivel	Visual inspection for signs of leakage.	
Monobuoy Main Body	Centre Swivel	Grease and rotate.	
Monobuoy Main Body	Pipework, brackets and flanges	Visual check for leaks and mechanical damage.	
Monobuoy Main Bearing	Bearing	Visual inspection of water barrage. Check turnbuckles are all OK.	
Monobuoy Main Bearing	Bearing	Grease Main Bearing and rotate Turntable. Check for smooth running.	
Turntable	Structure	Inspect and report any damage or corrosion on any parts of the structure and handrails, including safety bars on ladders to the crane, navaids gantry, chicksan and boarding platform.	
Turntable	Structure	Inspect all areas of the turntable and ensure that housekeeping is maintained at a high standard.	
Turntable	Top Valve	Visual inspection for leaks and mechanical damage.	
Turntable	Pipework, brackets and flanges	Visual inspection for leaks and mechanical damage.	
Turntable	Chicksan	Visual inspection for leaks and mechanical damage.	
Turntable	Expansion piece	Visual inspection for leaks and mechanical damage.	

Remarks

EOMPS Maintenance Task Sheet

Unit	Sub-Unit	Description	Completed
SHII 7			
Turntable	Brakes	Visual inspection for condition and operability.	
Turntable	Fendering	Inspect and report any damage or wear.	
Turntable	Lifebelts	Inspect and report any damage.	
Turntable	Fire Extinguishers	Inspect and report any damage.	
Floating Hose String	General	Visual inspection for damage, deformity and leaks.	
Floating Hose String	Floating Hose Sections	Visual inspection of Nuts and Bolts for damage and corrosion.	
Floating Hose String	Y-Tank	Visual check for leaks, reporting any unusual trim and mechanical damage to casing and floatation.	
Floating Hose String	Y-Tank	Visual check for leaks and mechanical damage to pipework and flanges.	
Floating Hose String	Y-Tank	Visual inspection for damage or corrosion to nuts, bolts and gaskets.	
Floating Hose String	Lights	Visual check of operation. If damaged replace unit and stanchion with appropriate light.	
Floating Hose String	Lights	Visual inspection for damage and corrosion, straighten stanchion as required.	
HPU	General	Fuel tank level check.	
Diesel Generator	General	Fuel tank level check.	
Crane	General	Check all pipes / hoses for fitting / leakage.	
Crane	General	Visual check for damage to crane structure.	
Crane	General	Check wire for condition.	

Remarks

EOMPS Maintenance Task Sheet

Unit	Sub-Unit	Description	Completed
SHII 7			
Crane	General	Grease all grease points until fresh grease appears at bearing or bushes.	
Crane	General	Grease pads on telescopic jib.	
Wind Generators	General	Visual and audible operational check.	
Solar Panel	General	Visual check for cleanliness and mechanical damage.	
Anenometer	General	Visual check for mechanical damage and operation.	
Fog Signal	General	Audible check when close to and leaving the Monobuoy. Report any defects.	
Navigation lights	General	Visual check for operation and cleanliness. Report any defects and clean as required.	
Navigation lights	General	Visual check of structure when close to Monobuoy or from tanker.	
Working Lights	General	Visual Inspection when on Monobuoy at night.	
Working Lights	General	Visual inspection of lamp bodies when on Monobuoy during daylight.	
Boarding Lights	General	Visual Inspection when on Monobuoy at night.	
Boarding Lights	General	Visual inspection of lamp bodies when on Monobuoy during daylight.	
Boarding Lights	General	Test both remote and local operation.	
Telemetry	General	Check telemetry battery condition and report any defects.	

Remarks

EOMPS Maintenance Task Sheet

Unit	Sub-Unit	Description	Completed
SHII 7			
Monobuoy Main Bearing	Greasing System	Check greasing system for excess grease at collection points and check blockage indicators on bearing and centre swivel.	
Monobuoy Main Bearing	Greasing System	Check level in grease supply container and and re-charge when empty.	
Monobuoy Main Bearing	Greasing System	Record counter reading - Start and Finish.	
Floating Hose String	Flanges and Nipples	Visual inspection for damage, corrosion and leaks.	

Remarks

EOMPS Maintenance Task Sheet

Unit	Sub-Unit	Description	Completed
BM 14			
BMs			OK?
Floating Hose String	Floating Hose Sections	Visual inspection of Rail Hose Lifting Lugs when connecting hoses to each tanker. Report any excessive wear or damage.	
Floating Hose String	Hose-End Valves	Visual inspection for leaks and mechanical damage.	
Floating Hose String	Hose-End Valves	Visual inspection for mechanical damage and corrosion of hose end valve nuts / bolts / spool.	
Floating Hose String	Rail Hose Rigs	Visual inspection of Hose Lifting Rigs for damage, corrosion and security of all components. Report any defects or deformities and replace components as necessary.	
Floating Hose String	Rail Hose Rigs	Visual inspection of Hang-Off Chains for damage, corrosion and security of all components. Report any defects or deformities and replace components as necessary.	
Floating Hose String	Rail Hose Rigs	Visual inspection of Kuplex Clutches for damage, corrosion and security of all components. Report any defects or deformities and replace components as necessary.	
Floating Hose String	Rail Hose Rigs	Visual inspection of Hang-Off Ropes for damage and wear prior to use. Replace as necessary.	

Remarks

EOMPS Maintenance Task Sheet

BM 14

Unit	Sub-Unit	Description	Completed
Hose Connection Box	General	Visual inspection of Hose Connection Gear Box for damage, corrosion and security of all components. Check lifting rig and shackles, report any defects.	
Hose Connection Box	General	Clean and grease Nuts and Bolts. Replace any damaged items.	
Hose Connection Box	General	Complete inventory, replace any damaged items and replenish consumables.	
Hose Connection Box	General	Check condition of hose webbing strop.	
Corrosion Inhibitor Skid	General	Visual inspection of Corrosion Inhibitor Skid for damage, corrosion and security of all components. Check lifting rig and shackles, report any defects.	
Telemetry	General	Check reading on portable unit and compare with Tetney remote reading.	
Telemetry	General	Comparison with tanker strain gauge, done with each ship where vessel has suitable equipment.	
Telemetry	General	Check contents of 'Briefcase' and replace missing items, including spare booklets, NOPs, Checklists etc.	
Pickup Rope	General	Check condition of Pick-Up Rope and report any defects.	

Remarks

EOMPS Maintenance Task Sheet

Unit	Sub-Unit	Description	Completed

Elec 31

Electrical

Unit	Sub-Unit	Description	OK?
Turntable	Structure	Check all cable connections for loose fittings and corrosion.	
Diesel Generator	General	Visual Inspection – check operation during Start/Stop.	
Crane	General	Check operation of limits and condition of switches cabling and glands.	
Wind Generators	General	Check bearing free play radial and axial.	
Solar Panel	General	Voltage output check 0-24 volts.	
Solar Panel	General	Check Solar Panel for water ingress and spray with water repellent.	
Solar Panel	General	Visual inspection for corrosion to terminals.	
Working Lights	General	Re-lamp as required.	
Boarding Lights	General	Re-lamp as required.	
Telemetry	General	Visual check for damage on Load Monitor plug connectors / cable.	
Telemetry	General	Visual inspection for water ingress into Telemetry Control Box, and spray with water repellent.	
Telemetry	General	Check voltage on each Telemetry battery.	
Telemetry	General	Clean Telemetry Battery Terminals and spray with water repellent.	
Telemetry	General	Inspect Telemetry Battery Box and clean filters.	
Telemetry	General	Compare voltage output at Telemetry Battery to that measured at Power and Control Box.	

Remarks

EOMPS Maintenance Task Sheet

Unit	Sub-Unit	Description	Completed
SHII 31			
SHII			OK?
Monobuoy Main Body	Tanks	Check on whichever tanks can be accessed, for water ingress by sounding and pump out as required. Record the tanks inspected and ensure that all tanks have been checked within a 3 month period.	
Monobuoy Main Bearing	Bearing	Lift two randomly selected water barrage covers and check inside barrage for signs of leakage.	
Turntable	Structure	Grease and rotate all sheaves on the Monobuoy Turntable.	
Turntable	Chicksan	Check chicksan bolt tell tales and torque up if required.	
Winch	General	Run winch in both directions for approx. 2 to 3 minutes.	
Winch	General	Inspect pulling wire.	
Winch	General	Grease all grease points until fresh grease appears from bearing.	
Winch	General	Grease manual brake spindle.	
Winch	General	Operate all changeover valves and check for ease of movement.	
Winch	General	Inspect all hoses from power pack to winch for damage / leaks.	
Winch	General	Check mounting bolts for corrosion / deterioration.	

Remarks

EOMPS Maintenance Task Sheet

Unit	Sub-Unit	Description	Completed
SHII 31			
Monobuoy Main Bearing	Greasing System	Remove excess grease from collection points.	
Monobuoy Main Bearing	Greasing System	Visual inspection of greasing system.	
Hawser	Tanker Mooring Point	Grease and replace grease nipples on tanker mooring point when required.	

Remarks

EOMPS Maintenance Task Sheet

Unit	Sub-Unit	Description	Completed

Eng 31

Engineers

OK?

HPU	General	Lub Oil sump level check.	
HPU	General	Cooling water level check.Observed at 42 c	
HPU	General	Fuel tank level check.	
HPU	General	Check save all for water and oil – empty if required.	
HPU	General	Visual check upon starting.	
HPU	General	Running checks: Engine Oil Pressure. 5.6 bar	
HPU	General	Running checks: Cooling Water Temperature.	
HPU	General	Running checks: Check for leaks.	
HPU	General	Check hydraulic oil storage tank level and note with date (Visga 32).	
HPU	General	Running checks: Check hydraulic pressure under load (250 bar). Operated at 110 bar :	
HPU	General	Running Checks: Check for leaks.	
HPU	General	Check for damage, chafing, leaks on the hrdraulic hoses.	
Diesel Generator	General	Lub Oil sump level check.	
Diesel Generator	General	Cooling water level check.	
Diesel Generator	General	Fuel tank level check.	
Diesel Generator	General	Save all to check for oil and water - empty as required.	

Remarks

EOMPS Maintenance Task Sheet

Unit	Sub-Unit	Description	Completed
Eng 31			
Diesel Generator	General	Inspect cooling fan hub and blades for cracking / damage.	
Diesel Generator	General	Check drive belts for tension and damage.	
Diesel Generator	General	Check for worn / damaged parts.	
Diesel Generator	General	Check operation of louvers (opening / closing).	
Diesel Generator	General	Running checks: Engine Oil Pressure. 82psi	
Diesel Generator	General	Running checks: Cooling Water Temperature.	
Diesel Generator	General	Running checks: Charging Voltage.	
Diesel Generator	General	Running checks: Check for Leaks. Obs at 27.6 V	
Diesel Generator	General	Running checks: Exhaust colour and quantity.	

Remarks

BWTX-20200501_0146

EOMPS Maintenance Task Sheet

Unit	Sub-Unit	Description	Completed

Diver 92

Divers

OK?

Unit	Sub-Unit	Description	OK?
Crane	General	Extend Monobuoy crane jib to full reach and inspect exposed surfaces for condition / grease. Where required apply grease to telescopic jib sections.	
Monobuoy Main Body	General	Carry out inspection of all the mooring gimble locking gates. Report any missing or loose items.	

Remarks

EOMPS Maintenance Task Sheet

Unit	Sub-Unit	Description	Completed

Grease 92

BMs

OK?

Monobuoy Main Bearing	Greasing System	Send grease sample off for analysis. Review results and establish any remedial requirements.

Divers

OK?

Monobuoy Main Bearing	Greasing System	Flush the bearing with grease through the four manual grease ports.

Remarks

EOMPS Maintenance Task Sheet

Poll 92

BMs

Unit	Sub-Unit	Description	Completed
Emergency Spill Trailers	Spill Trailer 1	Complete Spill Trailer 1 Checklist.	
Emergency Spill Trailers	Spill Trailer 2	Complete Spill Trailer 2 Checklist.	
Emergency Spill Trailers	Spill Trailer 3	Complete Spill Trailer 3 Checklist.	
Emergency Spill Bins	Spill Bin 1	Complete Spill Bin 1 Checklist.	
Emergency Spill Bins	Spill Bin 2	Complete Spill Bin 2 Checklist.	
Emergency Spill Bins	Spill Bin 3	Complete Spill Bin 3 Checklist.	
Oil Pollution Store	General	Complete Oil Pollution Store Checklist.	

OK?

Remarks

EOMPS Maintenance Task Sheet

Unit	Sub-Unit	Description	Completed

Pick-Up 92

BMs

OK?

Unit	Sub-Unit	Description	OK?
Pickup Rope	General	Arrange for pick-up rope to be end-for-ended to extend the working life of the rope.	
Pickup Rope	General	Withdraw rope from service when wear dictates. Arrange for new rope to be fitted.	

Remarks

EOMPS Maintenance Task Sheet

Unit	Sub-Unit	Description	Completed

Diver 183

Divers

OK?

Unit	Sub-Unit	Description	OK?
Sub Sea Hoses	Hoses	Physical check of flange and bolt tightness .	
PLEM	Non-Return Valve	Check flanges and tighten bolts as required.	
PLEM	Non-Return Valve	Visual check for corrosion on NRV. Check flanges and tighten bolts as required.	
PLEM	Non-Return Valve	Check condition of flat cap bolts on NRV.	
PLEM	Grove Valve	Visual check for corrosion on Grove Valve. Check flanges and tighten bolts as required.	
PLEM	Grove Valve	Visual inspection of stem seal on Grove Valve.	

Remarks

EOMPS Maintenance Task Sheet

Unit	Sub-Unit	Description	Completed

CP 183

CP

OK?

Unit	Sub-Unit	Description
PLEM	Anodes	Measure and record voltage potential on each anode.
PLEM	Anodes	All CP results reported back to ConocoPhillips.
Monobuoy Main Body	Anodes	Measure and record voltage potential on each anode.
Monobuoy Main Body	Anodes	All CP results recorded in CP report.

Divers

OK?

Unit	Sub-Unit	Description
PLEM	Anodes	Carry out dive on the PLEM and record / report condition of anodes. Assist with the measurement of voltage potential on each anode.
Monobuoy Main Body	Anodes	Carry out dive around the skirt of the Monobuoy and record / report condition of anodes.

Remarks

EOMPS Maintenance Task Sheet

Unit	Sub-Unit	Description	Completed

SHII 183

SHII

OK?

Crane	General	Test emergency winch lower procedure.	

Remarks

EOMPS Maintenance Task Sheet

Unit	Sub-Unit	Description	Completed

Chain 183

Inspect

OK?

Chaffe Chain - Tanker	General	Measurements taken to detect any wear and report on findings. Replace if wear exceeds 12% of original diameter. Original diameter = 76mm.
Chaffe Chain - Buoy	General	Measurements taken to detect any wear and report on findings. Replace if wear exceeds 12% of original diameter. Original diameter = 76mm.
Shackles	General	Measurements taken to detect any wear and report on findings. Replace shackles if wear exceeds 12% of original diameter. Original diameter = 115mm.

Remarks

EOMPS Maintenance Task Sheet

Unit	Sub-Unit	Description	Completed

Lift 183

SHII

OK?

Unit	Sub-Unit	Description	
Turntable	Divers Davit and winch	Monobuoy Diver retrieval davit and Sala winch to be Inspected and certified by a competent person under LOLER regulations.	
Corrosion Inhibitor Skid	General	Inhibitor Injection Skid lifting rig to be Inspected and certified by a competent person under LOLER regulations.	
Workboats	Spurn Haven II	SHII Diver retrieval davit and Sala winch to be Inspected and certified by a competent person under LOLER regulations.	

Remarks

EOMPS Maintenance Task Sheet

Unit	Sub-Unit	Description	Completed

Hose 183

Divers

OK?

Floating Hose String	Floating Hose Sections	Swim floating hose string and check condition of bolts. Tighten as required.

Remarks

EOMPS Maintenance Task Sheet

Unit	Sub-Unit	Description	Completed

Bridle 365

Inspect

			OK?
Turntable	Divers Davit and winch	Monobuoy Diver retrieval davit and Sala winch to be Inspected and certified by a competent person.	
Turntable	Tanker Mooring Bridle and Shackles	Measured and Inspected.	

Remarks

EOMPS Maintenance Task Sheet

Unit	Sub-Unit	Description	Completed

Lloyds 365

Lloyds

OK?

Unit	Sub-Unit	Description
Monobuoy Main Body	Tanks	All tanks opened and compartments visually inspected.

Remarks

EOMPS Maintenance Task Sheet

Unit	Sub-Unit	Description	Completed

Hose 365a

BMs

OK?

Unit	Sub-Unit	Description	OK?
Floating Hose String	General	Inspection of nuts and bolts in Grimsby Docks – replace as necessary.	
Floating Hose String	Floating Hose Sections	Inspection in Grimsby Docks. Full internal and external condition inspection with Dunlop technician. Replace hoses as required.	
Floating Hose String	Floating Hose Sections	Replace as required during annual inspection or on 10th inspection whichever comes first.	
Floating Hose String	Hose-End Valves	Hose-end valves to be inspected, and changed out as required.	
Floating Hose String	Marine Breakaway Couplings	Replace and test breakstuds on MBCs to inspection schedule.	
Floating Hose String	Flanges and Nipples	Inspection in Grimsby Docks – replace gaskets as necessary in any opened flanges.	

Remarks

EOMPS Maintenance Task Sheet

Unit	Sub-Unit	Description	Completed

SHII 365

SHII

OK?

Monobuoy Main Bearing	Greasing System	Change Greasing system filter elements.	

Remarks

EOMPS Maintenance Task Sheet

Unit	Sub-Unit	Description	Completed

Rope 365a

BMs

OK?

Hawser	General	Remove all floatation jackets, drift "D" Shackles and conduct a thorough inspection, complete checklist and record any defects.	

Remarks

EOMPS Maintenance Task Sheet

Unit	Sub-Unit	Description	Completed

Lift 365a

Inspect

Unit	Sub-Unit	Description	OK?
Corrosion Inhibitor Skid	General	Annual inspection and certification by a competent person.	
Workboats	Spurn Haven II	SHII Diver retrieval davit and Sala winch to be Inspected and certified by a competent person.	

Remarks

EOMPS Maintenance Task Sheet

Unit	Sub-Unit	Description	Completed

Eng 365

OK?

Engineers

Unit	Sub-Unit	Description	Completed
HPU	General	Visual check for corrosion / damage.	
Diesel Generator	General	Take engine oil sample for analysis. (sample to be taken from dipstick tube when up to temp.).	
Diesel Generator	General	Change oil and filter.	
Diesel Generator	General	Change fuel filter.	
Diesel Generator	General	Change air filter.	
Diesel Generator	General	Change drive belts if required.	
Diesel Generator	General	Drain cooling system, fill with clean water and top up with anti freeze Check anti freeze level with hydrometer.	
Diesel Generator	General	Check air charge cooler.	
Diesel Generator	General	Check valve clearances.	
HPU	Diesel Driver	Take oil sample for analysis (take from dip stick tube when up to temperature).	
HPU	Diesel Driver	Change oil (Disola W).	
HPU	Diesel Driver	Change oil filter.	
HPU	Diesel Driver	Change fuel filter.	
HPU	Diesel Driver	Change air filter.	
HPU	Diesel Driver	Inspect and change drive belts as required.	
HPU	Diesel Driver	Drain cooling system and fill with clean water and anti freeze. Check anti freeze level with hydrometer.	

Remarks

EOMPS Maintenance Task Sheet

Unit	Sub-Unit	Description	Completed
Eng 365			
HPU	Diesel Driver	Check air charge cooler.	
HPU	Diesel Driver	Check valve clearances.	
HPU	Diesel Driver	Test automatic shutdown system.	
HPU	Diesel Driver	Test injectors.	
HPU	Hydraulic Unit	Change filters if required. (see indicator on high pressure filter).	
HPU	Hydraulic Unit	Sample hydraulic fluid, send for analysis – (Take sample from tank, not pipework).	

Remarks

EOMPS Maintenance Task Sheet

Unit	Sub-Unit	Description	Completed

Elec 365

BMs

OK?

Telemetry	General	Carry out PAT testing of Berthing Master's gear used for tanker operations: Telemetry portable unit / battery chargers / cables / adapters / extension lead etc. Work to be carried out in association with PAT testing of workboat equipment.	

Electrical

OK?

Wind Generators	General	Remove and inspect slip ring brushes for wear, replace as required.	
Navigation lights	General	Change out full set annually.	
Earthing and Zoning	General	Check earth continuity of Monobuoy electrical systems.	
Earthing and Zoning	General	Disconnect all earth connections and copperslip / clean as required.	
Earthing and Zoning	General	Visual inspection of all zoned equipment.	

Remarks

EOMPS Maintenance Task Sheet

Unit	Sub-Unit	Description	Completed

Lloyds 912

Lloyds

OK?

Unit	Sub-Unit	Description
Monobuoy Main Body	Tanks	Full Lloyds Survey of Monobuoy, including hull thickness measurements.

Remarks

EOMPS Maintenance Task Sheet

Unit	Sub-Unit	Description	Completed

Hydr 1825

OK?

Engineers

HPU	Hydraulic Unit	Drain and prepare hydraulic reservoir and accumulator for inspection and re-certification.

Remarks

EOMPS Maintenance Task Sheet

Unit	Sub-Unit	Description	Completed

MBC 1460

BMs

OK?

Floating Hose String	Marine Breakaway Couplings	Send back to manufacturer for overhaul.	

Remarks

EOMPS Maintenance Task Sheet

Unit	Sub-Unit	Description	Completed

Stores 183

BMs

OK?

Unit	Sub-Unit	Description
Marine Stores	General	Half-yearly inventory of Marine Stores. Ensure stock levels are brought up to the minimum holding where required.

Remarks

EOMPS Maintenance Task Sheet

Unit	Sub-Unit	Description	Completed

CS 183

Divers

OK?

Turntable	Chicksan	Carry out six-monthly check on tensions on the Chicksan Bolts, and adjust as required.	

Remarks

EOMPS Maintenance Task Sheet

Unit	Sub-Unit	Description	Completed

Sealine Pressure Test

BMs

OK?

Sub Sea Hoses	Hoses	Pressure testing in situ of the hoses, and by extension the sealine, should be performed approximately every six months depending upon environmental conditions at the buoy. The test should consist of raising the internal pressure in the hose to its rated pressure, or its operating pressure + 50%, whichever is the lower, and then holding it for a period of three hours. Visual inspection of the system should only commence when the pressure has stabilised.
Sub Sea Hoses	Hoses	Add historical record to EOMPS database.

Remarks

EOMPS Maintenance Task Sheet

Unit	Sub-Unit	Description	Completed

Well Valve Telemetry

Electrical

OK?

Telemetry	General	Well valve telemetry showing red/green whether valve is open or closed.	

Remarks

EOMPS Maintenance Task Sheet

Unit	Sub-Unit	Description	Completed

Diver 31 - Chain Angles

BMs

OK?

Unit	Sub-Unit	Description
Monobuoy Main Body	General	Record measured angles in CHAINCAL.xls and advise any required adjustments. Make entry in the EOMPS section of the database where required.

Divers

OK?

Unit	Sub-Unit	Description
Monobuoy Main Body	General	Measure and record chain angles to ensure correct tension on each of the Monobuoy mooring chains.

Remarks

EOMPS Maintenance Task Sheet

Unit	Sub-Unit	Description	Completed

Diver 31 - Configuration

BMs

OK?

Unit	Sub-Unit	Description
Sub Sea Hoses	Hoses	Record measured values in HOSECONFIG.xls, print out result and file. Advise on any concerns making a record in the EOMPS section of the database.

Divers

OK?

Unit	Sub-Unit	Description
Sub Sea Hoses	Hoses	Measure and record spot locations on the sub-sea hose system to allow recording of hose configuration.

Remarks

EOMPS Maintenance Task Sheet

Unit	Sub-Unit	Description	Completed

Sub-Sea Hose Change

BMs

OK?

Unit	Sub-Unit	Description
Sub Sea Hoses	Hoses	Co-ordinate planning of routine Sub-Sea hose change. Ensure risk assessments and procedures are reviewed.
Sub Sea Hoses	Hoses	Oversight of the arrangements for supply of all equipment required to carry out planned operations.
Sub Sea Hoses	Hoses	Arrange for safe preparation and isolation of Sub-Sea hose system and Sealine prior to commencement of Sub-Sea hose change
Sub Sea Hoses	Hoses	Arrange for safe preparation and de-isolation of Sub-Sea hose system and Sealine on completion of Sub-Sea hose change.

SHII

OK?

Unit	Sub-Unit	Description
Sub Sea Hoses	Hoses	Carry out Sub-Sea hose change.
Workboats	General	Carry out preparation of workboats to carry out replacement of Sub-Sea hoses, including preparation of diving equipment, four-point mooring and auxilliary hydraulic equipment.
Workboats	General	De-mobilise workboats following on from Sub-Sea hose change.

Remarks

EOMPS Maintenance Task Sheet

Unit	Sub-Unit	Description	Completed

Grease 365

BMs

OK?

Monobuoy Main Bearing	Bearing	Check bearing drains (6 of) are clear.	

Remarks

EOMPS Maintenance Task Sheet

Unit	Sub-Unit	Description	Completed

BM 365

BMs

OK?

Corrosion Inhibitor Skid	General	Inspect mechanical condition of skid for damage and corrosion. Arrange for repairs as required.	
Corrosion Inhibitor Skid	General	Arrange for testing of skid as required.	

Remarks

EOMPS Maintenance Task Sheet

Unit	Sub-Unit	Description	Completed

Rail Hose Rig 183a

SHII

OK?

Floating Hose String	Rail Hose Rigs	Hose Lifting Rigs to be changed out very six months and returned to competent authority for refurbishment. After refurbishment and certification by a competent authority under LOLER regulations spare units should be stored on SHII ready for use.

Remarks

EOMPS Maintenance Task Sheet

Unit	Sub-Unit	Description	Completed

Rail Hose Rig 183b

SHII

OK?

Floating Hose String	Rail Hose Rigs	Hang-off chains to be renewed. Replaced units to be returned to Hammond and Taylor for refurbishment.

Remarks

EOMPS Maintenance Task Sheet

Unit	Sub-Unit	Description	Completed

Fire Extinguisher Maintenance

SHII

OK?

Turntable	Fire Extinguishers	Test and recharge Monobuoy fire extinguishers as necessary.

Remarks

EOMPS Maintenance Task Sheet

Unit	Sub-Unit	Description	Completed

Lift 365b

SHII

OK?

Unit	Sub-Unit	Description	OK?
Winch	General	Monobuoy winch and wire to be Inspected and certified by a competent person under LOLER regulations.	
Crane	General	Monobuoy crane and wire to be Inspected and certified by a competent person under LOLER regulations.	

Remarks

EOMPS Maintenance Task Sheet

Unit	Sub-Unit	Description	Completed

Rail Hose Rig 365b

SHII

OK?

Floating Hose String	Rail Hose Rigs	Kuplex clutches to be renewed. Replaced units to be returned to Hammond and Taylor for refurbishment.

Remarks

EOMPS Maintenance Task Sheet

Unit	Sub-Unit	Description	Completed

Rope 365b

BMs

OK?

Support Float	General	Thorough inspection for damage, and renew connecting chain and shackles.

Remarks

EOMPS Maintenance Task Sheet

Unit	Sub-Unit	Description	Completed

MBC 365

GT

OK?

Floating Hose String	Marine Breakaway Couplings	Carry out Annual Inspection of one MBC. Alternate yearly. Unit to be stripped down, inspected and refurbished as required.

Remarks

EOMPS Maintenance Task Sheet

Unit	Sub-Unit	Description	Completed

Leak 92

Divers

OK?

Leak Detection System	General	Carry out integrity test on sub-sea hose leak detection umbilicals.
Leak Detection System	General	Test telemetry alarm function on the leak detection system for the sub-sea hoses.

Remarks

EOMPS Maintenance Task Sheet

Unit	Sub-Unit	Description	Completed

Poll 183

BMs

OK?

Emergency Spill Trailers	Spill Trailer 1	Revalidate DADS certification for Pollution Equipment Trailers

Remarks

EOMPS Maintenance Task Sheet

Unit	Sub-Unit	Description	Completed

Instrument 365

Electrical

OK?

Pressure and Temperature Sensors	General	Annual calibration PPM done on temperature and pressure sensors.	

Remarks

EOMPS Maintenance Task Sheet

Unit	Sub-Unit	Description	Completed
BM 90			
BMs			OK?
Hose Connection Box	General	Visual Inspection of all hand tools	
Hose Connection Box	General	Inspection of long handled ring spanners to include audible "tap" test	
Hose Connection Box	General	Inspection of ratchet spanner(s) should include function testing of the ratchet mechanism and lubrication	
Hose Connection Box	General	Annual replacement of spanners to be carried out in first quarter	

Remarks

EOMPS Maintenance Task Sheet

Unit	Sub-Unit	Description	Completed

Seabed Survey

BMs

OK?

Unit	Sub-Unit	Description	OK?
Seabed	General	Arrange for survey of seabed within the Tetney Harbour Area by suitably qualified and authorised contractors	

Remarks

Humber Refinery

COTH 3696

Tetney MonoBuoy

MM Pre-Berthing Check List

PEARY SPIRIT

Date/Time:

	OK	Fault	Remarks
Pre-Berthing Discussion held with Department Heads			
Workboats Fully Available (Primary /Secondary or Substitute Vessels)			
Environmental Conditions within Berthing Parameters			
MMs Equipment Checked			
MM Equipment Bags Prepared for operations			
Gas Detector Checked and Available for Use			
Sundstrom Masks Checked and Available for Use			
Hand-Held UHFs and VHFs checked and Available for Use			
Portable Load Monitor Checked and Available for Use			
Tanker Mooring Available and Secured to Buoy			
Monobuoy and PLEM valves Prepared and Tested as per Import Work Instructions			

Mooring Masters Comments

____

____

____

Signed ....Mooring Master ***Items/Faults Noted ....***

TRENT FISHER

TETNEY MONOBUOY PRE-BERTHING CHECK LIST

James Fisher Marine Services

COTH No:		TANKER:		Date: Time:	

		OK	FAULT	REMARKS
1	Floating Hoses Visual inspection for damages deformity and leaks			
2	Floating Hose Lights			Number of Hose Lights in operation
3	Floating Hose Flanges Visual inspection for damage deformity and leaks			
4	Floating Hose String nuts and bolts. Visual inspection for damage and corrosion			
5	Valve Floatation. Visual inspection for integrity			
6	Tanker Mooring Shackles Visual Inspection for damage and loose pins.			
7	Tanker Mooring. Tape replaced as required inspection of splices, eyes & thimbles. Replace jackets were necessary			
8	Chaffe Chain / Connection Chain Visual inspection. Report any damage.			
9	Chain Support Float. Check connecting chain for excessive wear and that it floats correctly once in the water.			
10	Pick Up Rope Visual inspection whilst deploying. Report any damage and replace where necessary			
11	Lifting Gear Check lifting strop and BM's bag prior to use.			

RANK …………………………………………… **Signature:** ……………………………………………………

Trent Fisher Mate is to confirm they have Inspected item numbers 5-10 and report Any damage.

Signature: …………………………………………………….

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Marine Services

COTH No:		TANKER:		Date: Time:	

		OK	FAULT	REMARKS
1	Confirm the PLEM valve HPU system is in AUTO and confirm with the Trent Fisher			
2	Open turntable valve and confirm with the Trent Fisher Master that it is in the open position.			
3	Connect 110vAC flying lead. Confirm Batt volt >23.5v			
4	Charge up HPU accumulator			
5	The Trent Fisher Master will request the tank head pressure from Tetney Base on the sealine			
6	Tetney Base will confirm with the Trent Fisher / MM Stroke test can be performed			
7	Tetney Base will perform the stroke test and apply pressure			
8	Tetney Base to confirm test stroke is complete and the PLEM valve is in the closed position			
9	The crew will confirm the pressure on the turntable gauge and report back to the Trent Fisher Master			
10	The Trent Fisher Master will check the pressure and voltage on the telemetry back at Tetney Base			
11	Load monitor block visual check. Check Well valve is full open and report to Tetney			
12	Buoy / floating hose connection			
13	Turntable and well pipe work paying attention to the sea surface in the well			

14	Product Swivel			
15	Turntable and body for damage			
16	Manhole covers for security			
17	Turntable bearing for unusual noise or loss of free movement			
18	Navigation / Deck Lights			
19	ISPS Security Checks			
20	Any other comments			
21	Special Checks – Loadcell Retention Split Nut – Allen bolts tight?			

ENSURE FLYING LEAD DISCONNECTED AND CHARGE SWITCH IN OFF POSITION

RANK ....

NAME : ....

SIGNATURE: ....